COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:)
)
Informational Proceedings and)
Preparation of the 2003) Docket No.
Integrated Energy Policy Report) 02-IEP-01
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

WEDNESDAY, FEBRUARY 26, 2003

10:00 A.M.

Reported by:
Valorie Phillips
Contract No. 150-01-005

COMMISSIONERS PRESENT

James Boyd, Presiding Member

William J. Keese, Associate Member

ADVISORS

Scott Tomashefsky, Advisor

Susan Bakker, Advisor

Melissa Jones, Advisor

STAFF PRESENT

Al Alvarado

Karen Griffin

David Abelson

Bill Wood

David Vidaver

Magdy Badr

Judy Grau

Mark DiGiovanna

ALSO PRESENT

Steven Kelly, Policy Director
Independent Energy Producers Association

Tom Miller
Pacific Gas and Electric Company

Mark R. Minick, Manager of Generation Planning
Southern California Edison Company

Mark J. Skowronski
Duke Solar

Jeff C. Huang, Market Forecast Consultant
The Gas Company, Sempra Energy

ALSO PRESENT

David L. Arthur, Energy Supply & Marketing
Redding Electric Utility

Gary DeShazo, Regional Planning Manager
California Independent System Operator

Mark A. Meldgin, Senior Business Planner
Pacific Gas and Electric Company

Brian C. Prusnek, Regulatory Analyst
California Public Utilities Commission

Don Smith, Regulatory Analyst
Office of Ratepayer Advocates
California Public Utilities Commission

Morteza Sabet, Manager
Western Area Power Administration

Chifong Thomas, Principal Consulting Engineer
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Michael S. Alexander, Manager
Southern California Edison Company

Stephen Hall

Kent F. Hampton, Marketing Manager
Marathon Oil Company

William Marcus
JBS Energy

Joe Alves
BP Energy Company

Richard McCann
M-Cubed

Curt Hatton, Manager
Pacific Gas and Electric Company

I N D E X

P R O C E E D I N G S

10:00 a.m.

PRESIDING MEMBER BOYD: Welcome to day number two of Commission Committee's workshop on the integrated energy policy report and the electricity and natural gas report specifically. No introductory remarks today; we did all those yesterday, so I'm just going to, with Mr. Keese's permission here, Commissioner Keese, we'll dispense with any speeches and turn it right over to you, Al, to get into today's topic areas.

MR. ALVARADO: Okay. Good morning, everyone. This is the second day of the Integrated Energy Policy Report workshop. For those of you that weren't here yesterday my name's Al Alvarado. I am the Project Manager of the Electricity and Natural Gas Report, which is one of the three reports that are being prepared in support of the Integrated Energy Policy Report.

Yesterday we covered three staff draft reports; one was the demand forecast, and the other two were on our retail price forecasts, our preliminary forecasts.

Today we're going to cover two other reports. The first one will be on our preliminary electricity and natural gas infrastructure assumptions. And the second report will be on our preliminary cost of central station generation technologies.

As I said yesterday, we are recording this workshop, and the intent is really to track your comments. But it will require you to come up to the microphone and speak into the microphone so we can capture all your comments for our later review and making sure we're not missing anything.

When you do come up to the microphone can you also please pass on your business card to our court recorder to make sure that she'll be able to spell your name correctly. And despite this formality I do hope that we can foster a little more lively and open discussion since the purpose here really is to get comments from you.

With that being said, I'm going to pass on the mike to Mark over here who is going to initiate our discussion on the first report.

MR. DiGIOVANNA: All right, thanks, Al. My name is Mark DiGiovanna. I am the staff's lead for the preliminary electricity and natural gas infrastructure assumption staff draft report. And we did want to make that title longer, but they wouldn't let us, so --

(Laughter.)

MR. DiGIOVANNA: This report is intended to answer the question of what changes in electricity and natural gas infrastructure are likely to occur in the next ten years.

To do this we've broken this into three sections: electricity generation; electricity transmission infrastructure; and natural gas infrastructure.

In a moment David Vidaver will come up here and talk about the assumptions that we are making in what electricity generation infrastructure additions will be made in the next ten years.

He'll be followed by Judy Grau, who will talk about electricity transmission infrastructure additions.

And then finally I'll come up here and talk about the natural gas infrastructure additions that have come online since the energy crisis, as well as the several projects that we see coming online in the next few years.

Hopefully by the end of this what we'll have is a good set of assumptions on the resource additions that will be made over the next ten years. We will use this in all of our upcoming reports, which will be another electricity report which will be coming out in March; the 2003 natural gas market outlook report which will come out in April; the electricity and natural gas report which is obviously the policy report -- IEPR; and then the final IEPR.

So we would appreciate and hope that you'd give us as many comments as possible, as far as if these are reasonable assumptions, if you have knowledge otherwise. And from there we will be able to get all these other reports done.

One other note. I just want to reiterate what Al said, Valorie asked me to remind everybody to be sure to give her your business card if you want to make sure your name is spelled right in the transcript. And also to speak into the microphone. And if you're a repeat offender, if you spoke yesterday, you don't need to give her your business card, so you're all right there.

So, with that, I will turn it over to Dave.

MR. VIDAVER: Thanks, Mark. I usually start off by telling a joke to put myself at ease, because I don't like doing this. The only thing --

PRESIDING MEMBER BOYD: I noted the tie, David, I mean that was --

(Laughter.)

MR. VIDAVER: The only joke I could come up with this morning was really inappropriate.

(Laughter.)

MR. VIDAVER: And I'm sure it would really offend Karen, who would never let me near a microphone again. So, two FERC Commissioners walk into a bar -- it is too inappropriate to tell --

(Laughter.)

MR. VIDAVER: Gee, they taught me how to use this just a moment ago. Click on my name --

PRESIDING MEMBER BOYD: For the audience's benefit yesterday we tried to imply this is supposed to be a very informal workshop. We're stuck with the way this room is set up, but, you know, it should just be a nice, big giant roundtable. But we should have had David as the opening act yesterday morning, too.

(Laughter.)

PRESIDING MEMBER BOYD: To put the audience at ease a little more, so anyway, you're doing good, David.

MR. VIDAVER: Thank you, Commissioner. Chapter one, generation infrastructure. A little overview of what we're going to talk about. An outline. We're going to briefly discuss changes in resource adequacy for 2000 to 2003, very quickly.

Assess current market conditions, perhaps not as quickly, but we all know what they are. Natural gas is trading at about $19 right now. So that's the bad news. The good news is that SoCal border prices are trading at about a 40 percent discount.

Then we're going to go over likely changes in infrastructure from 2004 to 2006. We have some idea, we'll admit we're sort of guessing. And solicit your input as to what you think is going to happen.

And then 2007 - 2013, I wanted to type about 15 question marks there. Go over some of the uncertainties, all of which I'm sure you're familiar with.

Then roll out our baseline projections for your critique, and some of the scenarios and sensitivities that we're going to run. The baseline is just designed as sort of a plausible set of additions, off which we can analyze sensitivities. The conclusions we come to, to the underlying assumptions that we make.

So, that being said, can't discuss resource adequacy without nodding toward demand. As Lynn Marshall discussed yesterday, peak demand has fallen since 2000 these are the weather-adjusted ISO peak loads. The horizontal black line are the normalized monthly peaks, so you can see we've done a pretty good job of conserving. I believe those numbers are adjusted for things moving in and out of the ISO; the City of Pasadena and SMUD.

New generation. These are the plants 200 megawatts and larger that have come online since 2000. They've actually come online since 2001. None of these came online in 2000. So you can see we've built quite a bit of capacity.

Some of that is actually dedicated to California loads. I believe Sunrise is; a couple others are, too, but -- never mind.

The procurement review --

MS. JONES: David, what's in the other category?

MR. VIDAVER: What's in the other category? The 1873 megawatts of plants less than 200 megawatts.

MS. JONES: Okay, thank you.

MR. VIDAVER: Okay? Sorry. Everything over 200 is broken out. If I begin to like shiver violently and my head jerks back, it's because I have access to information related to interim procurement.

And if I accidentally reveal anything that I'm not supposed to, Karen is going to jolt me here. So if I just go whoops in the middle of a sentence where I'm talking about a particular power plant or a particular contract, I hope you'll understand.

We've also got a number of plants which are going to come online between now and the end of this summer. And while in the past some of the projections about capacity due to come online have been optimistic, as it were, these are pretty much done deals.

Four of those should be online within the next three months. Elk Hills, for example, is a Sempra plant, and Sempra has obligations under a DWR contract that it cannot currently meet out of its own capacity, so Elk Hills is done.

High Desert is in a similar position. That's a constellation contract with DWR or through DWR. Sunrise is another one of those plants I don't think I could say exactly when it will come online, because Karen will jolt me. But it's part of a DWR contract, as well.

And I believe La Paloma 2 and 4 are actually testing as we speak, so. That's another 3300 megawatts of capacity that we should have online by the end of the summer. If you add those up you get about 9300 megawatts of new capacity.

And the trend growth rate in load in California is such that we need about 1200 megawatts of capacity each year. So we've basically added something like seven years worth of capacity, in a loose sense, since 2000.

The Northwest. Loads have dropped dramatically in the northwest for a number of reasons. Most notably the utter collapse of the aluminum industry which constitutes about 6 percent of northwest loads. I think eight of the ten smelters in the northwest have shut down.

There is very little indication that any of that load will return. Aluminum prices are very low; these smelters tend to use an obsolescent World War II era technology. The preferential entitlements that they receive from BPA are probably going to be slashed in 2006 from I believe it's 2800 megawatts down to 600.

The remaining aluminum industry in the U.S. is moving to the Ohio Valley. And China will probably become the world's largest producer of aluminum by the end of the decade.

These loads are not weather adjusted, so you can't just look at them and say, well, in 2002 whatever conservation appeared in the northwest the prior year had disappeared. Unfortunately I can't provide you a weather-adjusted set of data. The Northwest Power Pool provides that for energy, but not for peak loads. There is some recovery in the northwest, but it's not substantial.

Not only has there been new capacity in California, there's been a lot of it throughout the remainder of the WECC. The triangles represent plants which are now online larger than 200 megawatts, have come online since 2000.

Again, we expect quite a bit of capacity to come online elsewhere in the WECC by the end of the summer. The Calgary Energy Center began testing on Monday, for example.

The Mesquite plant is another -- yes, ma'am?

UNIDENTIFIED SPEAKER: I'm confused. This one includes California, too?

MR. VIDAVER: Well, --

UNIDENTIFIED SPEAKER: This 6649?

MR. VIDAVER: No; the 6649 is the total amount of capacity outside of California that is not online but expected to be online by the end of this summer. Sorry.

The Mesquite plant is another Sempra owned plant which will, in all likelihood, be dedicated to serving California loads. The TDM plant, Thermodynamica Mexicali, is another Sempra plant, which barring transmission constraints, will be used to satisfy load in California.

The Goldendale plant is highlighted; it's the one located at the Oregon/Washington border. It is probably not going to make the summer deadline, almost certainly.

This information changes daily. We scour the web and the trade press on a daily basis and things move in and out. But for every plant that gets canceled, delayed, for example, like

Goldendale, we just heard yesterday that SUMAS 2, a 600 megawatt facility at the Washington/Canada border is almost certainly going to go forward. I think they were actually approved, and then because of delays they had to refile. And they've done that.

So for everything on here that might slip there's something else that might actually appear, not by the end of the summer of 2003, but certainly within the next two years.

So, the bottomline is we've seen a substantial increase in reserve margins, both in California, the northwest and the southwest. Again, you're talking about six and seven years worth of load growth being met by this capacity.

So the conclusion is that resources are adequate to insure reliable, competitively priced electricity through 2005. Now, there are some caveats.

Competitively priced electricity doesn't mean cheap electricity. And here we're talking about the wholesale spot market. Today the ISO -- energy market is trading well over $100 -- slightly over $100. But with gas prices at the border being in the $11 and $12 range, that's perfectly understandable.

There is really no amount of generation capacity that can guarantee low gas prices. And as our gas office will probably talk about this afternoon, gas prices probably won't remain low. They'll probably stay high for a couple of years. But I'm not the one to talk about that.

MS. JONES: David, you talked a little bit about the northwest loads. Can you just briefly talk about what's going on with loads in the southwest?

MR. VIDAVER: The southwest load data is really hard to get a handle on. They don't have such agencies as the Northwest Power Pool and the Northwest Power Planning Council. So, compilations of their recent loads are really tough to get ahold of.

It's my understanding that loads in parts of the southwest, specifically southern Nevada, are actually not slowing down. But the loads in Arizona are declining somewhat. That would no doubt be a result of the macroeconomic situation.

Those arguably will remain the fastest growing areas of the country. And the extent to which loads continue to grow there will probably be -- they'll probably only be dampened by price increases, which they've experienced. And blamed on us, by the way, so.

CHAIRMAN KEESE: Let me ask, are capacity withdrawals included in this? Or is that another -- are we going to hear about that later?

MR. VIDAVER: We haven't -- there's nothing in this presentation which indicates how much capacity has come offline in the past two years. It's a very very small amount.

However, as of December 2002, some capacity was constrained by the South Coast Air District, which required that some plants shut down because of failure to install emissions retrofits. Ron Weatherall is not in the audience, but --

CHAIRMAN KEESE: I thought I recalled 1300 megawatts.

MR. VIDAVER: Yeah, I was going to say it's about 1200 megawatts. But actually some of that has -- a share of that has received approval from the Air District to install after-the-fact emissions retrofits and actually come back online. So the actual number is probably going to turn out to be slightly below 1000.

So, recent spot market conditions. We've gone through the last six or seven months of 2002 because of gas prices that are low by recent standards. We've experienced very very low spot market price.

I've provided two series here. The red series is the ISO imbalanced market price. These are sort of unweighted monthly averages. The imbalance market price is an average of the ISO's (inaudible) prices. May or may not have much meaning. So we also provided the economic inside survey price. They're a group in Oregon which is part of the industry, trade press.

So we're seeing prices crawl back up. In fact, in the last six weeks they've crawled back up at about 65 miles an hour. We have very high prices right now, but what you have to keep in mind is that the high prices are not a result of a lack of generation capacity.

There was an article in a recent, I think last week's Power Markets Weekly that implied that we're back to 2000 in large part because of the hydro conditions in the northwest. And I would strongly disagree with that. Bill

Wood in our gas unit can provide you far more accurate information about the run-up in gas prices than I can. But I can assure you it doesn't -- I would like to assure you that it has nothing to do with capacity shortages.

Even if spot market prices stay at the level they're at now, we've dramatically reduced our exposure to the spot market. I've provided some numbers here related to the three investor-owned utilities.

What has basically happened is that the DWR contracts, combined with the interim procurement proceeding, have dramatically lowered the exposure of the investor-owned utilities and its customers to the spot market.

I guess taking this in order, the utilities have their own thermal assets consisting of hydro and nuclear units primarily. They also have QF contracts. They have must-take DWR contracts. About 90 percent of the energy under those contracts is at fixed prices; very little of it is exposed to gas price risk. And that which is can be hedged. I understand the utilities can hedge gas prices right now. They have other long-term contracts with WAPA and BPA, out-of-state entities.

And then the DWR dispatchable contracts, most of which are indexed, I think all of which are indexed to the gas price, leave the utilities with some gas-price exposure. But, they can hedge that, unlike four years ago.

So the total capacity available to them onpeak is about 4000 shy of what they're going to need. So this is saying that they have to go out in the spot market for 4000 megawatts during the hottest hour of the year.

Well, two things should be noted. None of the interim procurement numbers are in here. If we told you what those were we'd have to kill you. So, assuming that half of that has been taken care of, you can say that onpeak the utilities are going to have to go out into the spot market for 2000 megawatts.

Well, they always have the possibility of signing balance -- quarter contracts; and can effectively reduce their spot market exposure to nothing if the PUC so allows it.

The other thing to remember is that the peak hour of the year is indeed that, it's peak hour. And you only get to within a couple thousand megawatts of that maybe five or ten hours of the year.

Even during the rest of the summer you're usually, 2-, 4-, 5-, 10,000 megawatts, 5000 megawatts shy of your peak. So what this is saying is that the exposure of the investor-owned utilities in the spot market during the summers of 2003 and 2004 is negligible.

So while we may not like the fact that we're faced with the possibility, given current gas prices, of paying $100, $150, maybe even more, in the spot market for electricity this summer, the financial risk associated with that is minimal for the investor-owned utilities.

MS. BAKKER: David.

MR. VIDAVER: Yes, ma'am.

MS. BAKKER: I notice that says coincident peak demand, and I didn't think we did coincident peak demand forecasts. Are you just adding them and assuming the worst case?

MR. VIDAVER: No. The demand office has actually calculated the relationship between coincident and non coincident peaks for the state. And they've come up with a factor of about .976. So if you take the non coincident, some of the non coincident peaks and you multiply that number by .976 you get a very good estimate of the coincident peak.

MS. BAKKER: Okay, and then this is just the IOUs?

MR. VIDAVER: This is just the IOUs, and it's net of direct access. And, of course, we're making an assumption about what share of the IOU load is going to stay out with direct access contracts.

And I believe the assumption we made was something on the order of 12 or 14 percent.

Yes, Mr. Kelly.

MR. KELLY: Dave, just for clarification, so I understand. This is IOU only?

MR. VIDAVER: Yes, sir.

MR. KELLY: And when I think of IOU peaks in the summer I think of about 45,000 megawatts. What you're showing is that -- are you showing that here?

MR. VIDAVER: Well, I'm trying to. If you're thinking of 45,000 you're a little high.

MR. KELLY: Okay.

MR. VIDAVER: Sorry, I mean your number's a little high.

(Laughter.)

MR. KELLY: I like the way you did it the first time.

MR. VIDAVER: We've also reduced, if you take 38- or 39- or 40,000, whatever number you're thinking of, and you reduce that by about 12 or 14 percent, which is what direct access is taking away from them, you're getting down to these --

MR. KELLY: Okay. So in a hot summer day the IOUs collectively will be -- their residual net short -- the short-term market will be roughly 10,000 megawatts that they'll have to procure? If you're at 42, roughly?

MR. VIDAVER: Well, if you were sitting up at 40 --

MR. KELLY: Eight --

MR. VIDAVER: Yeah, if you were to add 6000 to the 34, you'd be looking at 10 for the --

MR. KELLY: Thank you.

MR. VIDAVER: Okay. A lot has been made of a number of cancellations of new projects. For the past 18 months or so, we've read in the newspaper about how every single megawatt of capacity that anyone has even thought of is no longer in the development stage.

So we thought we'd take a look at some of these numbers very quickly. These are applications at the Commission which have been withdrawn since July 2001. July 2001 was when prices all of a sudden returned to something resembling normalcy.

These are, again, only plants larger than 200 megawatts. So, that's quite a bit of capacity that's been withdrawn, as everybody is so fond of pointing out.

We then have a number of plants which have actually been permitted, some of which have begun construction, that they haven't -- they're not going to meet the online dates that we set perhaps a year ago.

For example, I don't know exactly what we assumed that the online date for Pastoria would be when we permitted it, but it's certainly not going to make that date. I believe that only 250 megawatts at Pastoria is actually in an advanced state of construction. I'm not sure. Someone from the siting office will no doubt correct me.

Contra Costa has stopped construction. Otay Mesa and Metcalf are in red because they have the unique characteristic that the state actually has a right to step in and finish building them if Calpine does not meet construction milestones. So I'd like to highlight them. They're also important for another reason which we'll get to shortly.

Mountainview has been postponed, Russell City, et cetera, et cetera. So, these are all plants which have been permitted. Some of which, indicated by the C's on the map, are actually under construction.

One thing to note about this is that in the event that it were profitable to do so, these plants could probably come online a lot faster than a plant which is yet to submit application, or have an application approved.

And here are some of the plants that are in review at the Commission. Again, it's an almost complete list of plants over 200 megawatts. There are a couple of plants which are missing. The Magnolia plant that Burbank and SCAPA would like to build. The Walnut plant which is, I believe, the Turlock Irrigation District plant; I didn't put on this list, and I'll explain why shortly.

But everything else here, East Altamonte

1100 megawatts, I believe, is the third plant that the state has step-in rights on. Blythe II is highlighted because I got into kind of an argument with the siting division. Blythe II walked in kind of recently, so they -- it's unfair to say that they are being delayed. They haven't shown any indication of not wanting to come online quickly.

But I put them in here because I wanted to give you an idea of despite all the cancellations, despite the low forward prices in the market, this is how many people are still interested, to some extent, in building power plants. Whether or not they actually want to get them online the day after tomorrow -- well, they probably want to get them online the day after tomorrow with prices at $100, but that's a more recent phenomenon.

What we have here is despite all the cancellations that we've heard about and people toss around numbers like 50,000 megawatts WECC-wide that are no longer on the drawing board, we still have built enough, put enough steel in the ground to meet load for quite some time. By our estimates, the year 2005.

And it should also be remembered that while many of these delays are being attributed to the financial conditions of the developers, we hear numbers of like anywhere between $40- and $90 billion worth of short-term debt, that these developers will, in all likelihood, not be able to service over the next 12 to 18 months, that these permits and these partially constructed plants are not going anywhere.

They're actually changing hands. Pacific Gas and Electric's National Energy Group actually completed La Paloma, which is over 1000 megawatts, but it will never see one megawatt of output. It got the financing to complete that with the agreement that when it was done it would simply turn the facility over to the bank.

So, even if all of these facilities are turned over to creditors, it's very likely that the creditors will turn around reasonably quickly and turn them back over to other developers at somewhere, depending on who you believe, between 20 and 50 cents on the dollar. Banks do not like to hold these assets. They will turn them over whenever they think the person to whom they're turning them over can cover the debt that they incur.

PRESIDING MEMBER BOYD: David.

MR. VIDAVER: Yes, sir.

PRESIDING MEMBER BOYD: I'm a little bit worried about what the title of this slide, expected delays, conveys to the lay public vis-a-vis those of us who sit around knowing the exact status of various things.

I mean, as a Commissioner who sits on some siting cases, I mean some of those are going slower, let's say, in the permitting process than one would have hoped, but that's due to not necessarily financial conditions or any desire to build, it's just a tough project to permit, and they're going slow.

So, some of these are going slow, but I don't see the fact that -- I don't see that they're not going to be built and be online vis-a-vis some that the intricate financing web you wove there may be caught up in that.

So I think I just want to caution the audience that -- and the media, in particular, that you really got to get down case-to-case. And I don't want to convey that, oh, boy, we're expecting delays in all these projects. Because some of them are just going slow permitting-wise, but we don't, in a few cases I know specifically we don't see any reason why they won't be built and operated.

MR. VIDAVER: I could have chosen the title far more carefully. We normally expect the siting process to take a certain length of time. And following that we have an 18- to 24-month construction period. And given the location of these projects in queues, we would expect an online date at some point in the future.

The fact that these plants will probably not come online, with the exception of Blythe II, at that time is not a function of problems encountered in the siting process. And in these cases it's not necessarily a result of financing problems.

The simple fact is that until a couple days ago, forward prices were so low that it didn't make sense to bring a power plant online. You could not cover debt service.

So, these delays are primarily a result of the fact that you want a placeholder in the queue to build a power plant, assuming that at some point in the not-too-distant future it will be profitable to operate.

But I received permission from the head of our siting office to say that many of these plants are in no hurry. Now, the events of the last couple days may change that, but in any case, until recently forward prices have been such that whatever incentives there are to apply for a permit, there have not been substantial incentives to get that plant online really quickly. So I hope that clarifies what is meant by this slide.

All righty, now we get down to the fun stuff. Looking forward, we're in an environment where we can't look forward with any degree of certainty. We don't have -- we don't model single utility areas, we don't use screening curves, we don't know what exports or imports are going to be available, and we don't know what gas prices are going to be. And we don't necessarily sit down with load serving entities and come to some kind of consensus of these matters.

So, what we have tried to do in establishing a baseline resource assessment is come up with a plausible future. What this future entails is a bit of guesswork and some basic assumptions about what the future will look like.

With respect to some of these plants that we are going to assume are built and come online during the next three years, we have what we think is very very solid information. And I'll go over these individually to give you an idea as to how confident we are, in some cases, and how much conjecture is involved in others.

We see in California from the end of the summer of 2003 until the beginning of the summer of 2006, 4200 megawatts of capacity coming online.

Los Angeles Department of Water and Power is repowering two major units which would otherwise have to shut down for failure to install appropriate emissions controls. These are their Valley facilities and the Haynes facilities. Haynes is in red, as are a couple of other bits of information. This indicates that the numbers or the dates or the names have changed since the February 13th document that we issued.

So, as I said, this is a very dynamic environment; we're constantly trying to keep up with the set of rapidly changing facts. And accordingly, the numbers of two weeks ago aren't necessarily the numbers today. So, for example, we didn't assume that Haynes was going to be repowered until about ten days ago.

So, LADWP is repowering about 1100 megawatts of capacity. There will be another slide which shows how much capacity we think is being retired. The difference between the Haynes repower and the amount of capacity being retired by LADWP is guess about 49 megawatts.

Salton Sea 6 has a 20-year contract with the Imperial Irrigation District to sell 100 percent of its output. It's going to be built.

Several of the remaining plants, Vernon, Walnut, Magnolia are owned by municipal utilities that are either replacing them with new facilities or find themselves onpeak caught short in the market, and are arguably attempting to reduce their exposure to the spot market; or they have long-term contracts expiring. And so we're very confident that these plants will be built, especially if spot market prices stay at $100 for any length of time.

Kings River peaker and the San Francisco Airport peakers are the turbines that were secured from Williams. They're in contract renegotiation. We say San Francisco Airport, because it's probably the one place in the City that nobody cares if they have a power plant next to them. So we're just being a little sensitive to their needs. There is no San Francisco Airport site.

Pico is another one of those muni-owned plants; it's being built by Silicon Valley Energy, or the City of Santa Clara. Cosumnes is being built by, or would like to be built by SMUD. And, again, this is a municipal utility short on peak. And we figure they're very very serious about building this. Municipal utilities have captive load, as it were, and they have basically have a pretty much a guaranteed revenue stream which will allow these plants to prove profitable. MID Cogen is another plant being built by a load serving entity.

The two shaky ones on here, as it were, are Metcalf Energy and Otay Mesa. We happen to think that Otay is going to go forward, in large part because it resides in a local reliability area. Somebody is going to have to build something in San Diego. It may not be Otay Mesa, it may be Palomar, it may be somebody who hasn't even walked in through the front door yet.

But one element of the assumption we're making is that capacity is expanded in a rational fashion. I'm going to get to that in a little more detail as we discuss 2007 and 2013, but fundamentally we assume that whether it's the market or the state or some combination thereof, we're not going to be caught short again. You may quibble with that assumption and we are certainly planning to model a scenario in which an inadequate amount of capacity is built, leaving us perhaps short in 2006 or 2007.

But as a baseline assumption, set of assumptions, we believe it's rational to assume that, or logical to assume that whatever the market can't provide the regulator can. No laughter --

So, this is the baseline set of assumptions regarding power plant additions in California 2004 and 2006. And, of course, we welcome comment. We expect some.

Those additions didn't include additions that we think will result in the renewable portfolio standard. I'm not going to go into the details of the RPS.

We think that the capacity required to meet RPS targets through 2006 will be built; that those targets will be met. We also feel, however, that a share of the energy needed to meet those targets is going to come from existing renewables and resources. A sort of back-of-the-envelope estimate that we did showed that over 1000 megawatts of renewable capacity might be -- existing renewable capacity might be eligible to sign RPS contracts.

You'll see that we assumed three technologies would be used to meet the RPS targets, biomass or biofuels, geothermal and wind. We don't want to leave anybody out. Our renewable office has told us that they expect PV solar to meet a small share of requirements.

At present we do not plan to model that explicitly in our simulations for a couple of reasons. One, it's very small; and two, it's not that we're lazy, but we don't have a good profile of how PV is going to generate. We might be able to put one together pretty quickly, but we know that geothermal plants generate using a certain daily pattern that really doesn't vary from month to month.

We know that wind turbines generate in patterns that have both seasonal and daily variation, as well as geographic. We have quite a bit of data from San Gorgonio, Tehachapi, Altamont. So we can model the daily and seasonal profile of wind units.

What we have difficulty doing is assessing how much more efficient new turbines are going to be. The wind turbines in California, for the most part, are ten or more years old. Advancements in turbine technology mean that wind generation is going to be a lot more efficient over the next ten years. How much more efficient is open to question.

We have heard from some quarters that our numbers, our capacity factors of 33 to 38 percent, depending on whether you're talking about Altamont or Tehachapi or San Gorgonio, are unduly optimistic. We've heard from other quarters that they're unduly pessimistic. So any input you can provide on this would be appreciated.

In terms of the profile we're going to use historical data which indicates, for example, that the wind does not blow during the summer and during the afternoon in certain parts of the state. We're going to inflate that profile so it seemingly blows harder, given new technologies. But that's a simplifying assumption we have to make. Again, any input you have to offer on that assumption and how it could be revised, greatly appreciated.

Again, a share of the 2006 target is assumed to be met with existing resources. I really can't go into any details about those assumptions because they're based, in part, on the 2003 interim renewable procurement proceedings, which are confidential.

And finally we show you the amount of output that we think is going to come from new renewable resources under the RPS in 2005 and 2006.

MS. JONES: David.

MR. VIDAVER: Yes, ma'am.

MS. JONES: How much of the existing resource from renewable have you included in the resources estimate?

MR. VIDAVER: We model, for simulation purposes, all existing renewable generation. So we assume that existing renewable resources, a share of them will continue to generate under QF contracts; a share of existing resources without contracts will be used to meet RPS targets; and a share will have neither a QF nor an RPS contract.

MS. JONES: About how many megawatts are you talking about there?

MR. VIDAVER: Oh, I couldn't say with any degree of confidence, but probably -- we're talking about 1200 megawatts that don't have contracts, so probably somewhere between 500 and 800 megawatts of that would continue forward without a contract.

CHAIRMAN KEESE: So, specifically Salton Sea Geothermal is not here because it's contracted to Imperial and won't meet the RPS needs of the IOUs?

MR. VIDAVER: Correct. We also do not have a really current handle on how much renewable capacity is going to be built by municipal utilities. We did not assume that the munis participated in the RPS. We've already been proven wrong to some extent. LADWP has announced the intention of bringing 120 megawatts of wind online by next year. SMUD has demonstrated a desire to bring 15 megawatts on as soon as possible, and more later. These are updates that we're going to have to make to our assumptions.

Retirements in 2004 and 2006, 2500 megawatts. This is a deceptively large number;

513 megawatts at Valley, and the 304 megawatts of derates across the Haynes Units are basically going to be offset by repowerings at those sites.

With two exceptions, the remaining units are all municipal owned, and they're going to be replaced by newer facilities. Pardon me -- with four exceptions. The Alamitos GT and Etawanda 5 are owned by merchant generators. These are units that are going to have to come down under rule 2009 of the South Coast Air Quality Management District. They have not installed appropriate emissions control technologies, and the owners do not feel it economic to do so at this time.

Hunter's Point, we bring down, it's part of what we refer to as the San Francisco solution. You notice we built peakers in San Francisco. We bring the remaining still operating Hunter's Point Units down. I'm going to talk about San Francisco in more detail shortly.

The other major unit that we assume comes down is Mojave. We're talking about 1.5, an estimated $1.5 billion according to some sources that it would take to keep Mojave running. We think it's prudent to bring it down.

Yes, sir.

MR. MINICK: Dave, I don't disagree. Mark Minick, Southern California Edison, Manager of Generation Planning. I don't disagree with Mojave being removed. The date's wrong; should be December 2005.

MR. VIDAVER: Oh, it sure should.

MR. MINICK: Yes.

MR. VIDAVER: My apologies. Oh, yeah, wow. I don't know how that one slipped through. Yeah, we knew that, Mark, thank you.

(Laughter.)

MR. VIDAVER: We really did. Yeah, thank you. My, that's embarrassing. Okay, so, these are the retirements that we assume.

You're talking about, I thought I had this number memorized, but you're talking about 1700 megawatts net plus when you compare the additions and retirements. And that doesn't include the RPS numbers. So, if you toss in another couple hundred for dependable renewable capacity, geothermal and biofuels, you're talking about 1900 megawatts of net increased capacity from the summer of 2003 to the summer of 2006.

And if you look at our demand analysis office's demand forecast, you see a growth of about 4700 megawatts in required capacity, in load plus another 15 percent for reserves. So, we're losing, let's see, do my math here, we're losing about 2000 or 3000 megawatts of reserves over the next two or three years, which we think is reasonable given current low forward prices. They're not so low today, but -- and we remind you that the amount of capacity that was added from the summer of 2003 more than makes up for our not keeping up with load growth for 2004 to 2006.

CHAIRMAN KEESE: Excuse me, before you leave that --

MR. VIDAVER: Mr. Miller.

MR. MILLER: Tom Miller, PG&E. And on Hunter's Point 1 and 4, unless you have better information I think that's still PG&E, not Mirant, as far as the owner.

MR. VIDAVER: Yeah, we knew that, too.

MR. MILLER: Okay.

MR. VIDAVER: Thanks. Why did I decide it was Mirant? I don't know.

CHAIRMAN KEESE: Are these more in the character of firm retirements? These are the --

MR. VIDAVER: Actually, the Valley and Haynes, which are being repowered, are certainly firm. I would include Olive and Magnolia as very firm. In part because we assume that they're being replaced by facilities which are under review. And we believe have every intent of going forward, coming online.

The Alamitos and Etawanda units could actually, with the permission of the Air Quality Management District, install the appropriate emissions controls and come back online. So, we're being conservative in assuming that they don't.

Hunter's Point is part of a solution. It's a compromise. We don't, given the local opposition to Hunter's Point, we don't feel it appropriate to assume a future in which it continues to operate.

Mojave, you'll have to talk to Mr. Minick about what's going to happen with Mojave. I'm sorry. The utility claims that it would be very expensive to allow it to continue to operate.

MR. MINICK: It isn't just the expense on Mojave. Mojave has water and coal issues that we have made many filings with the PUC regarding. And until those issues get resolved by the other parties, we think it's imprudent to think that

Mojave can't continue.

It has a federal abatement order against it that it has to be cleaned up by December 31, 2005, to continue operations. At best it would be shut down for a number of years before it could continue to operate. And you can read the PUC filings that we've made on that particular issue.

The property is still owned by the joint participants. To say it couldn't be used for something else might be wrong. And Edison's resource plan filing on April 1st will address possible uses of the facility.

But at least in 2005 Mojave, as it presently exists, will cease. Whether it's a year or two shutdown and restart as a coal plant, or whether it's a restart as another kind of plant, we can address that later.

CHAIRMAN KEESE: Thank you. I'm thinking of two particular areas. The Pittsburg area where I have heard that there might be some plants running into the emissions bubble that could well go offline; and plants, older plants that do not have contracts. They don't necessarily have to shut down, but they may wind up being shut down because there's no market for them to find.

Now, is there another list like that, that if it firms up would join this list?

MR. VIDAVER: Yes and no. We hesitate to include plants such as those that you've mentioned, or those subject to those conditions on a list of retirements prior to the summer of 2006.

What history has taught us is that the retirement decision is something that's very very complex, and plants tend to stay in some state of availability, whether it be perhaps on six-months notice, for quite some time after a static economic snapshot would seem to indicate that they should be unavailable.

Regarding the possible retirement of those plants from 2007 onward, that's something I'd like to return to later in the presentation.

CHAIRMAN KEESE: Thank you.

MR. KELLY: Dave, you had indicated earlier, at least from the IOU perspective, you thought they were okay through 2005, which in my mind raised a question about what about 2006.

And when I look at your charts for the 2004, 2006 baseline additions, those are primarily muni additions.

MR. VIDAVER: Yes.

MR. KELLY: And when I look at the retirements they're about 50/50 it looks like, or 60/40, with a lot of IOU retirements. And from the statewide perspective things might measure out okay, but is there a potential problem from the IOU perspective for 2006 and beyond? How do we stand there on that?

MR. VIDAVER: Certainly the residual net short of the IOUs increases gradually over time. It stays, absent considerations of which of their plants might retire, i.e., Mojave, it stays surprisingly low through 2007. It's in 2008 when the DWR contracts are such that all of a sudden there's a substantially greater exposure to the spot market.

I'd like to put that aside for a minute, and at the same time refer backward to something that I said. And that is we want to assume that there's kind of a rational expansion of the generation infrastructure. And decisions going forward regarding retirements, or assumptions going forward regarding retirements obviously influence what you assume about what needs to be built.

So I sort of like put that aside. It's perhaps the most important question that can be asked here, and I want a chance to offer our approach to that in more detail, and then let the entire audience quibble with it probably in about ten minutes.

San Francisco and San Diego, despite all the optimistic sort of rose-colored statements that I've made, the fact remains, as Mr. Kelly pointed out, that while we may be in good shape from a statewide perspective, we have local concerns.

In particular there are two areas of the state which require action in the near term. In part because the solution to the local reliability problems that these areas face may be a transmission solution. In fact, it's likely to be one, which means we better get our act together pretty quickly, because it's going to take five years perhaps to actually implement the solution that we come up with.

These areas are, of course, San Francisco and San Diego. Now, what we've done is assumed a set of additions, retirements and transmission upgrades that we think doesn't necessarily solve the local reliability problem, but at least alleviates it.

And we would very much like input on this, especially from Robert Sparks and the ISO. If the solutions that we proposed are not adequate, and the ISO and other parties think that more needs to be done, we want to know about it so we can put it in our baseline.

The San Francisco solution is 180 megawatts of peakers located at the airport or on top of the Fairmont Hotel, or somewhere. Increase the transmission -- the transfer capability on the Jefferson-Martin transmission line by 400 megawatts. Even though that may have to be built underground.

Retire Hunter's Point 1 and 4, which is something that the City of San Francisco would like to see done. And then finally, in 2009 we see the need for additional capacity in San Francisco.

The San Diego upgrades include the upgrades at Mission Miguel, increasing the ability to move power from the Miguel substation into San Diego by 500 megawatts. Adding Otay Mesa or

Palomar or whatever you assume at the end of 2005.

Increasing the south of SONGS transfer capability by 750 megawatts in 2009. This is the Valley-Rainbow project. We don't mean to imply that it will take until 2009 to get done. We don't mean to imply that it won't be needed until 2009. This is just what we feel to be a reasonable assumption. If the ISO or anyone else believes that it's reasonable to expect that that upgrade occur sooner, we'd love to know about it.

I have two people who -- well, one didn't like what I said and walked out. The other one was kind of curious --

(Laughter.)

MR. SKOWRONSKI: Mark Skowronski from Duke. If you transfer 750 megawatts from SONGS what happens to the power going north?

MR. VIDAVER: It's increasing the transfer capability on the line, allowing power to move south of SONGS into San Diego. It's not a contract which would require the power to do so.

MR. SKOWRONSKI: I'm saying I'm sure San Diego and the L.A. area would have basically the same peak at the same time. I mean, are you double counting here?

MR. VIDAVER: I don't think so. This is just allowing -- this is an upgrade which I'm probably going to ask Robert Sparks to come up here if I have to get very technical, or Mark Hesters, if he's in the audience -- this is just an upgrade which would allow power to move from the Edison service area south to San Diego. I hope I've characterized that right.

Doesn't mean power will actually move; it just -- it reduces the need to keep generation up and synchronous in the San Diego basin, I believe, Encina, et cetera.

And finally, in January of 2009 we add 415 megawatts of capacity in the San Diego area. The existing South Bay unit, which I believe is owned by Duke, or excuse me, it's owned by -- it's kind of confusing. It's operated by Duke and owned by, I believe, the Port of San Diego. Will have to find a new home. It will have to be retired. And we assume that not only will that capacity be replaced, but an additional 415 megawatts or so will be added in San Diego at that time. Any comments on these two are actively encouraged.

I want to quickly go over some of the

assumptions that we've made about areas outside of California. We presented in our February 13th document a set of assumptions about load growth outside of California.

We received load forecasts for areas outside of California from a vendor. This has been revised recently by the vendor. So that the growth rates that were published two weeks ago are no longer those which we're going to assume in our simulations.

The vendor has come to his senses and realized that the aluminum industry is dead, so demand in the northwest is going to be lower for the indefinite future. And here you see that the peak demand, unfortunately all we have time to provide was the non coincident winter peak demand in the northwest, has dropped by anywhere from 2 and 3 percent in the short run to 1.7 percent in the long run, compared to the previous forecasts, the numbers that we presented two weeks ago. The energy numbers for the northwest don't drop quite that much.

We've also revised our numbers for the southwest. Our publication two weeks ago said the southwest was going to grow at about 2.7 percent.

That's low. We've revised those numbers upwards to about 3.5 percent. Those may ultimately prove to be too low, as well. But given the higher prices that the southwest is facing during the next couple of years, we think that growth rate is at least reasonable through 2005, 2006.

So what this is basically saying is that whatever export potential that the regions outside of California have realized during the past couple of years due to capacity growth is, while not likely to be sustained, those areas are in surplus. The demand, at least in the northwest, is going to stay low for the indefinite future.

May I defer to the guest, first? Mr. Kelly.

MR. KELLY: Dave, real quick. My understanding is the northwest is even in a more severe recession than we are. Is that steeper curve in the first 2003/2005 reflecting kind of roaring out of the recession at that period of time? Is that what we're seeing there?

MR. VIDAVER: Yeah. All the demand forecasts you're looking at now, whether they're for California, the northwest or some other part of the country, and whether they're done by us or someone else, are assuming at some point the economy is going to recover. And the growth rates from the point at which it begins to recover for a couple of years are going to be in -- the demand forecaster will tell you -- but in the 4 percent range as opposed to 2 percent. And then we'll return to normal.

So, Mr. Abelson.

MR. ABELSON: Thank you, Dave. David Abelson from the Energy Commission Legal Office. On your regional demand forecast for the northwest and the southwest, yesterday during our demand presentation, the issue of whether or not that includes conservation programs going forward, whether or not that includes self gen that might, you know, take off from the main grid system and so on, was a key question.

Can you help us understand what assumptions you're using on those issues for your demand in those regions?

MR. VIDAVER: I wish I could. As I said, we get these forecasts from a vendor. And this vendor utilizes forecasts done by various entities in the northwest. Among them, the Northwest Power Planning Council, the Northwest

Power Pool. So whatever assumptions we're using are basically the assumptions that are being used by those entities going forward.

The Northwest Power Pool compiles forecasts from member utilities. There are some 40-odd utilities which submit individual load forecasts to the power pool, which the power pool then compiles.

Now, I was in a resource adequacy forum in Portland recently, at which the person who compiled these forecasts complained that nobody used a standardized method for compiling their forecasts.

So some of the forecasts probably make rather optimistic assumptions about conservation and efficiency; others perhaps ignore it. On the self gen side, that's an issue that we have with the vendor.

You have two ways of dealing with self generation. And I'll illustrate this by example. You have a cogeneration facility which is going to build a 100 megawatt plant. And it's going to stop purchasing its power from the utility and it's going to generate it, itself.

And it's going to take 50 megawatts of

that cogeneration capacity and use it to meet its own load. Well, you have a number of ways of dealing with this. You can add 100 megawatts of capacity to the system, and ignore the fact that the utility is not going to be serving 50 megawatts worth of load. Or you can add 50 megawatts to the system of capacity and reduce your load forecast by the 50 megawatts that the utility is not going to serve.

It's not obvious to us how the vendor deals with this problem. And we've been talking to them about it.

So, while we expect self generation to increase, and I believe Lynn Marshall in the demand office made that statement yesterday, we expect it to increase as much in the northwest and in Canada. Alberta's experiencing incredibly volatile prices. If you think California has been a disaster, go to Alberta. They've had -- their annual price volatility is up in the order of 2000 percent. They go from offpeak prices of $10; three hours later they're $800.

What you're seeing up there is the most of the major industrial facilities, many of which do enhanced oil recovery, are building their own facilities to get away from that price risk that they're facing. And it's a challenge for people who try and assess resource adequacy and do forecasts to track the effect of that generation on load and load forecasts and fundamentally dealing with it in a consistent fashion.

So, it's something we're working on. Any real nerds who are interested in this problem, please come up and talk to us. I hope that answered your question.

The remainder of the WECC, of course, going to add capacity over the next couple of years, as well. These are our current best estimates, subject to change, of what capacity they're going to add.

I spoke with someone in Alberta the other day, a representative of EpCor. He said Genesee is certainly going forward. The second part of Mesquite, again this is a Sempra-owned plant and they have obligations under DWR contracts that are far in excess of the current amount of capacity under their control.

TDM, Thermodynamica Mexicali is again in that category. Santan in the Phoenix area, just turned over the first shovel of dirt. Any scenario in which we wanted to assume a very conservative estimate about capacity going forward would remove quite a bit of this.

So when we do a scenario in which the amount of capacity added over the next two to four years is below expectations, we will be removing a good share of this.

And, again, these numbers will probably change, even for the baseline, between now and the time we actually do the simulations. And if you happen to have any personal knowledge of power plants that are going to come online in the next couple of years in Idaho, please let us know.

This is kind a segue, this is our transmission topology. The models that we use assume that load and supply is located in various areas that are constrained with respect to the ability to move power in and out of them.

The numbers in red are the upgrades that we're assuming. You can see, for example, the upgrade to the Jefferson-Martin line in the upper left that we assume is going to take place in January 2006.

You see the Path 15 upgrade; Path 26 upgrade; the dates and the increases in transfer capability that we're assuming.

The Valley-Rainbow project, or some upgrade to the south of SONGS path. Again, the upgrade at Mission Miguel.

Over in Arizona the path between Palo Verde and the major load centers in Arizona, there are several transmission projects underway. These are our best estimates as to how transmission capability is going to be affected, transfer capability is going to be affected between Palo Verde and the Arizona load centers to the east.

The only upgrade that we have in California that's not currently, at the very least, under discussion is an increase in the transfer capability from the Imperial Irrigation District service area into Edison.

We assume that in 2009 that the transfer capability on this path is increased by 1000 megawatts. We did this to make our RPS forecast internally consistent. We'll talk about the long-run RPS capacity addition assumptions. We assumed that a substantial amount of geothermal capacity in the Imperial Valley is going to be developed over the next ten years. For that to be transferred to the purchasing utilities it will require an upgrade of this particular path.

Again, if the ISO wants to weigh in on how much of an upgrade is going to be required, we'd love to hear from them. We understand that they're probably going to have to do that as part of a proceeding later this year, in any case. And we'd like them to keep us apprised of their work in that regard.

I mentioned we did not assume any transmission upgrades elsewhere in the WECC beyond the Palo Verde, Arizona upgrade and the small upgrade, I think between Utah and Wyoming. I'm not sure.

We're going to add another upgrade. We're going to expand the ability of power to move from western Montana over the Cascades into the load centers along the coast in the northwest by about 600 megawatts, I believe, effective sometime in late 2004.

Because of the decline of the aluminum industry and the reduction in loads in various parts of the northwest, it's increasingly difficult to move power from several major facilities in the southwestern Montana/eastern Idaho region, Coal Strip, Libby and Hungry Horse, it's increasing difficult to move power to load centers in the west. And BPA has asked to upgrade the transmission line increasing the capacity, I think, from 2200 to 2800 megawatts.

I may have the numbers wrong, but for those transmission junkies out there, we're going to model that upgrade. And again, any other upgrades to the transmission system whether in California or outside it that you think we should model, please let us know.

Steve.

MR. KELLY: Dave, it looks like the PUC is moving forward on a Tehachapi upgrade. My understanding is the PUC is at least looking at strongly the Tehachapi upgrade to bring in the wind from that area. And I don't think it's on here, so.

MR. VIDAVER: The topology that we use is not so detailed as to explicitly model the Tehachapi radial line as constrained. I sort of sense the ISO cringing at the thought of not accounting for that. But Tehachapi lies in the same area as the rest of Los Angeles, as far as our model is concerned. So when we add wind capacity in the Southern California Edison service area, we implicitly, if not explicitly, assume that whatever transmission upgrades are necessary to keep that capacity from being stranded are, indeed, -- indeed take place.

We appreciate the information. I saw one of our staff write that down.

PRESIDING MEMBER BOYD: David.

MR. VIDAVER: Yes.

PRESIDING MEMBER BOYD: You just ventured into an area that gives me a lot of concern, and that is assumptions that are made. And Mr. Kelly's question just prompted a question that was rattling through my mind as to, you know, the generation of a policy report, which is our responsibility. And a responsibility to identify issues that need to be addressed, and that perhaps have been identified but for days, weeks, months and years and decades, sometimes, have been identified as needing to be addressed.

But it leads to my question to you, what level of probability do you assign in your mind to i.e., the success of a project before you find it -- it finds its way onto your chart?

And the reason I say that is not complete newcomer to this arena, but before I ended up on the Commission I was locked up in a room with a lot of people for two or three years on the energy crisis. And one of the things we did was, of course, identify Path 15 as desperately in need of upgrade; set out on a project to have that done in the depths of the crisis. Only to have that project, let's just say, aborted by a decision of the PUC to have a then-nearly-bankrupt utility take the responsibility.

So, my concern is we have a responsibility in identifying policy issues and the areas that need to be expedited. So, the wind example is another one that's been -- I've been aware of for more than four years now. And yet it's still a problem, et cetera, et cetera.

So we have to dice out those things that are policy issues that need to be brought to the attention of the Legislature and the Administration, if not the public. And so we'll have to continue to have that discussion internally.

I mean I have pages of questions and underscoring here that I'm not bothering to dump out in the public arena, but there are a lot of these kinds of issues that I think we have a responsibility to identify.

So I guess I'm just putting you on note, and others on note, that we have to deal with some of these. But don't forget my question about what degree of comfort or probability level did you assign before you threw it up there with the date.

MS. GRAU: With respect to Tehachapi, I just want to point out if you have a copy of the infrastructure report, in table B-9, which is on page B-20, we have all of the Southern California Edison transmission projects. These are all compiled in a table. These are all the ones that the utilities report on a monthly basis the status to the PUC. And it can also be found in their latest transmission plans.

And you'll see the Tehachapi transmission line project has a PTO ID number, and they are currently projecting the online date for an upgrade in that area as December 2006.

So these are staff's assumptions. The only ones that Dave is talking about are the ones, like you said, that affect the transmission topology, the big ones that affect inter-utility or a few intra-utility lines.

So these in the table is a complete listing of everything. And they don't make it into this level, the macro level he's diagramming here.

PRESIDING MEMBER BOYD: Well, believe it or not, I read every single page of all these reports, totally ruined a weekend, but -- and I appreciate that. And I just, I guess I'm just saying for the benefit of everybody here, that there are things that need to be pulled out and brought forward out of obscure tables and appendices and made policy issues that we all have to wrestle with.

Which is why this and these kind of public sessions are so important. And it's important for people to speak up and point out these little policy nuances that we should be focusing on.

So, it's a comment, not a criticism at all.

MR. VIDAVER: Not taken any other way.

CHAIRMAN KEESE: Dave.

MR. VIDAVER: Yes.

MR. HUANG: Jeff Huang with Sempra Utilities. I'd just like to point out that there's no physical link between Palo Verde and Los Angeles. The link is actually between Palo Verde and southern California SCE bubble. And then there's a link between L.A. and SCE. But your capacity is correct.

MR. VIDAVER: Okay, we'll talk to the person who put this together. And maybe he'll point to the diagram that he drew and show where it matches what you say, and not what I have here.

Yes, sir?

CHAIRMAN KEESE: Are you moving on from talking --

MR. VIDAVER: Please.

CHAIRMAN KEESE: I have one question that I would like to raise at some point. And that is one of the obviously identified security risks in California is the security of our linear system electric transmission, which places us at risk. I don't know that we have a report telling us what that risk is.

Has there been any consideration of the role transmission augmentation might make in reducing that security risk? Is there any thought of putting that in this report?

MR. VIDAVER: To answer the second

question first, I don't believe there's been any thought along that line, but Karen Griffin would be far more qualified than I to answer that.

CHAIRMAN KEESE: Okay, I'd like to raise it at some time.

MR. VIDAVER: The ISO, I'm sure, has a better answer to that question than I do. And if there is anyone in the Commission who can talk about that, a discussion of that issue in a broader context, I would assume it's our office of emergency services in the, I believe it's still called the fuels something office.

PRESIDING MEMBER BOYD: Well, on the point that Chairman Keese brought up, one of my concerns is the post 9/11 security issue as the Commissioner who got handed off this allegedly low-key responsibility of being liaison with the Nuclear Regulatory Commission. I am steeped in security now.

And so I worry about security of all legs of the, and components of the system. And the question about transmission is a good one I'm quite concerned about. The interaction between the electricity system and other types of systems that fuel our economy such as transportation fuels, which means refineries and those kinds of operations.

And those of you, during the crisis, can remember some frantic moments when blackouts were going around, shutting down other important pieces of our infrastructure, and struggles to keep the pipeline flowing, because otherwise we'd cripple the public, et cetera, et cetera.

I worry about keeping refineries going and therefore I'm really interested in self gen and cogen, and that's all part of the generation picture. So that, too, is another part of the energy policy responsibility I think this Commission now has to worry about.

So, I think it's a good question. That's something we'll have to all wonder and worry about to some degree. It's not just the physical security of a piece of equipment. But it is building in other parts of the system to either back up or assure greater reliability in the less-than-secure times. So, another point well taken that Commissioner Keese has brought up.

Just makes your report that much more difficult, doesn't it?

MR. VIDAVER: I think I'd like to deal

with your concerns regarding the underlying assumptions that we make and the probabilities that they'll be realized by reiterating that we assume here that with respect to the upgrades needed to operate the system that they occur in a timely fashion between the market and the regulatory agencies that things turn out okay.

And then do sensitivities to illustrate the consequences of getting something wrong.

Going back to the renewable portfolio standard, the additions that we assume. Once we get out to 2006 we assume that all renewable portfolio targets are, incremental targets are met with new capacity. And you can see the megawatt numbers. We assume that most of that capacity is wind, although from an energy perspective it doesn't dominate to quite that extent.

We locate most of this geothermal capacity in the Imperial Valley, as we believe this is where the most potential development lies. A small share of it is located north of Path 15.

Regarding the available wind generation we assume that again most of it is located south of Path 15. We appreciate any comments on the breakdown of this latter number.

Again, we assume a capacity factor for new wind generation in the 33 to 38 percent range. Any comments you have on that are welcome. But rest assured that they will be contrasted by someone who believes the exact opposite.

So, the amount of generation by 2013 is sufficient to meet the targets that our renewables office says will be in place by 2013.

Okay. Now, if 2004 to 2006 was conjecture, 2007 to 2013 is off the chart. There are several ways we can approach the task of building out a resource assessment through 2013.

There are models out there which purport to have algorithms which tell you exactly when power plants should be added; exactly when power plants should be retired; and exactly what type of power plants should be added. Whether it should be a gas turbine or a combined cycle.

The model we use doesn't have this capability and we don't think we're missing anything. The simple algorithms that estimate optimal addition and retirement basically estimate revenue streams at the facility level. You don't make enough money for one year or two years, you retire. The model shows that it's going to be profitable to operate next year, you build.

The world isn't so simple. These types of models ignore the risk associated with not having a long-term contract for output, the hurdle rate to build a plant when you don't have a long-term contract for your output is much higher than it is when you do.

It presumes that the price volatility estimates from your model are accurate, or ignores them completely. The more volatile market prices are the more profitable the peaker is. Most of the models which purport to yield optimal investment plans completely ignore this.

Finally, most of these models ignore revenue from non energy markets, the possibility of revenue streams from ancillary services, from RMR contracts and for peaking units from capacity payments.

And finally, on the side of retirements, they ignore how complex a decision it is to retire a plant. We were told back in 1999 that by 2005 the aging capacity in California would be all but gone. And we knew at that time, and we still maintain that capacity from a modeling perspective is not going to drop off the face of the earth.

That requires dismantling.

And in most cases, even the most aged and most inefficient capacity in our fleet is going to remain around for awhile in some state. It might not generate. It might take two months, six months, come back online.

We witnessed during 2000 and 2001 plants which hadn't operated in years all of a sudden surfacing to take advantage of high prices.

So we don't feel that in not having a model which analyzed the addition of retirement decisions using some complex black box that we're missing anything. The question then becomes, well, what do we do.

As i've stated several times, we think it's prudent to assume that additions and retirements provide the desired level of reliability. That if the market doesn't yield an adequate amount of capacity that the state will step in and make sure that that capacity is built. And the market will not over-provide, either.

This approach does not assume any particular role of the state in electricity markets as we move forward. It's compatible with a market in which the state plays virtually no role. And private development produces all necessary capacity.

It's also consistent with the role where private development is eliminated and the state does everything. So I don't think we need to get into a philosophical debate about which is more efficient.

So, that being said, the question then becomes how much capacity yields the desired level of reliability. And we realize that that depends largely on not only the functioning of the market, but regulatory decisions which have yet to be made, and perhaps even yet to be thought about.

We propose using reserve margins that prevailed in 1998 and 1999 as sort of a target to which the system will return over the long run, and then remain as we move forward.

The first question then is, well, pick one, damn it, 1998 or 1999. It's not that easy to do because the peak in 1998 was something like a one-in-five-year peak, and the peak in 1999 was like a four-in-five-year peak. So it requires some degree of interpolation.

Perhaps even those reserve margins are a little too high. As we build new capacity which has forced and maintenance outage rates that are quite low, the fleet becomes far more efficient, in which case we might need less capacity than we did ten years ago.

So, that's what we propose to do, is look on a transmission area-by-transmission area basis at how much capacity and retirements return us to conditions that prevailed in 1998 and 1999. Some degree of flexibility is required. For example, during those years prices north of Path 15 were higher than prices south -- higher than prices south of Path 15. Indicating that during those years there was perhaps a need for more capacity in the northern part of the state.

So, what we propose to do is look at the results that our initial baseline runs yield in terms of prices, and reliability, and modify it to take into account certain anomalies that would prevail if we return capacity margins to 1998 and 1999 levels on a transmission area specific basis.

The ultimate reserve margin will depend on what regulators do in response to the market. It could be that the reserve margins in 2010 will prove to be much higher because of a risk-averse attitude adopted on the part of regulators. They could prove to be much lower because of an efficient regulatory regime and a relatively efficient market.

We don't propose to know the answer to that question. We do propose that when you see our baseline and you see our numbers to comment.

Yes, sir.

MR. ABELSON: Of the various historic timeframes you might have used as your target for reserve margins, what was it that caused you to focus on the two years of '98 and '99?

MR. VIDAVER: Well, let me -- more recent years. If we go back to the reserve margins we had in 2000, you're walking a regulatory tightrope. You've getting prices which are indicative of the ability of generators to exercise market power.

It would require the assumption that an appropriate regulatory monitoring function be in place that prevents that from happening.

You may ultimately be right; that may be the equilibrium -- pardon me, I was trying to -- that may ultimately prove to be the equilibrium level of reserves. It could be that that amount of capacity, despite the ability of generators to manipulate the market, will be in the future the amount of capacity and the size of the reserve margin that will prevail, with a little better job on the part of state and federal regulators controlling the exercise of market power and manipulation in spot markets. So, 2000 certainly is an alternative.

By 2001, given all the conservation we observed, the system is over-built. By 2002, even moreso. Going back to 1995, '6, and 1997 the system was obviously in surplus. Although quickly heading toward disaster. But those reserve margins would be far too high. The simulations that we've run indicate that the prices that come out at those reserve margins don't sustain developers.

DR. ARTHUR: Dave Arthur, the City of Redding Resource Planner. I have to confess I'm slightly astounded that one would select 1998 and 1999. That was, I take it, what we actually had and two years later we had a disaster where we had shortages. We were not able to respond to a sudden growth in the economy at that level of reserve margin. We were not able to respond to a drought that occurred coincident with that.

I can't imagine that one would select that reserve margin, having gone through what is arguably a $20- to $40 billion experience that cannot be survived a second time.

I would hope that we have a reserve margin that is adequate to address the unexpected growth in the economy; to address droughts which are not predictable; and address other kinds of contingencies that can come along under Murphy's Law at the least convenient time.

And if we learned anything it seems to me over the last few years it's that having a little too much is not a serious problem. But having too little is very very serious. And unfortunately, I don't see that kind of thing being addressed.

PRESIDING MEMBER BOYD: Well, I --

CHAIRMAN KEESE: I'll just --

PRESIDING MEMBER BOYD: Go ahead.

CHAIRMAN KEESE: -- comment, since the circumstances of 1998, which led to the Commission's analysis that we were going to have a problem and which we, our staff pointed out in early 1999, and we tried to sell to people with limited success.

I would agree with you that we can't go back to the situation we had in '98 because in 1998 we had absolutely no infrastructure on the horizon, and we had a timeline of almost five years to get it started.

My analogy is I presented was we were -- the airplane was going down and it wasn't starting very high. We anticipated that by the year 2000 if everything had just stayed the same we would have a zero reserve margin.

So I think we can say the reserve margin was adequate; it was the rest of the system that didn't have it on a level course, had it going straight down.

So, if I had to pick I would say I think we are in the right at '98 or '99; we'll have to look at it. Are you giving us a number?

MR. VIDAVER: Am I giving? Oh, no.

(Laughter.)

CHAIRMAN KEESE: You're just going to say '98 or '99?

MR. VIDAVER: Yeah. No, we're not going to give you a number. We'll give you a number at some point. I just --

CHAIRMAN KEESE: You're going to give a

range sometime?

MR. VIDAVER: Yeah. Tom, I'm sorry, I just want to make one comment to Dave. And that is one of the purposes of the scenarios that we're running is we're going to run low hydro, booming economy scenarios. And what they will yield, if you're correct, is that we'll have problems, which indicates then, okay, the 1998 reserve margins are not suitable. And at which point we should probably go back and revise the baseline along the lines that you suggested.

So I hope that assuages some of your fears.

MR. MILLER: This is Tom Miller, PG&E, again. David, I was wondering if you could explain how you implement your method for Path 26, where there was, you know, considerable buildout of generation and a change from the '98, '99 period as far as reserve margins?

MR. VIDAVER: That's a -- you could help us answer that question. Path 26 is unique in that it's in the central part of the state where you have a whole lot of power plants and nobody lives there, except control room engineers, I guess.

And assuming you have enough capacity along Path 26 which sends energy south, and Path 15 which sends it north, Path 26 is really kind of, it's a nonentity. It doesn't really impact anything. So, in deciding -- a case could be made to not locate any generation in ZP26. Just to see what happens.

Because if you have a lot of capacity south of Path 15, and not enough north, you get congestion along one path going north, and vice versa, you get a congestion along another path going south.

So, I'm not sure the decision about where to locate -- and please correct me if I'm wrong, and I'd like Mr. Sparks to do the same thing -- the decision about how much capacity to place in ZP26 is not nearly as significant as the decision whether to place capacity south of it or north of it.

One of the considerations was that it seems to be a popular place to locate power plants. And that as such, we might as well continue to locate them there.

MR. MILLER: The reason I asked because if you are determining the reserve margin on a transmission area basis, and ZP26 being a transmission area, then if you see no need, I mean in other words the reserve margin didn't decline from the '98/99 period, you might, in effect, have a cushion, the reserve margin because of the generation built out there.

MR. VIDAVER: Yeah.

MR. MILLER: Is that true?

MR. VIDAVER: Yeah, because -- maybe I can answer this another way. We don't really worry about the reserve margin in ZP26. We worry about the reserve margins north of Path 15 and south of Path 15 and assume that what we build in ZP26 contributes to those reserve margins in those areas as long as those paths are not congested.

When they become congested we then take a look at them more carefully.

MS. JONES: David, can I just -- I have a related question about transmission. Wouldn't it be valuable to do a scenario in which you have the generation additions, but since, in effect, there are no transmission, major transmission upgrades going forward, none have been approved, wouldn't it be important to know what the implications of not expanding our transmission system are on the electricity system?

MR. VIDAVER: I think that certainly would be a useful thing to do. My only observation would be that there might be, depending on the questions you wanted to ask, there might be better tools to use.

For example, if you wanted to ask how prices would differ across transmission zones. It would be a very useful thing to do. If you wanted to ask are there going to be problems during peak hours with system reliability, there might be better models to use such as power flow models that look at the ability of the system to deliver energy under adverse conditions during peak hours.

So the answer to your question is it would be -- yes, it would be a good thing to do, but you have to keep in mind that depending on the questions you want to answer there might be better tools.

So that would be a scenario that we could certainly run. For example, what if you didn't expand Path 15.

MS. JONES: Thank you.

MR. SKOWRONSKI: Yesterday we covered basically demand, what the IOUs and everybody will be needing. And today I guess we're covering generation. But I don't see the marriage here with respect to, you know, what's the bottomline. When do the lines cross? Various scenarios of demand and various scenarios of generation. Do we have any finality here with respect to matching the generation with the demand?

MR. VIDAVER: Well, we're choosing the set of supply assumptions so as to look at the effect of those assumptions given the demand that was talked about yesterday on such things as price, both generally and by transmission area.

The variables that affect -- demand is sort of the driver. You have to have a good demand estimate before you know what supply is going to be. Because only enough supply is going to be built in a rational world so as to meet demand.

So in a sense you kind of have to start by dealing with them separately. And all the uncertainties here about what the appropriate baseline is, and what the appropriate adjustments are to it when you run scenarios bring supply and demand together.

MR. SKOWRONSKI: That's my point. I

mean do we have a slide that actually shows that? I'm just kind of fuzzy of how the generation and how the demand lines are meeting. I see a lot of different scenarios, but do we have a baseline assumption or recommendation or --

MS. GRIFFIN: I'm Karen Griffin; I'm the manager of the overall project. That's the next step. If we work through the demand assumptions and then the supply assumptions, and the natural gas assumptions, and transmission, and the next step is a set of analysis that we call supply adequacy.

So as we finish today then staff will go back and start working on that product.

MR. SKOWRONSKI: Okay.

MS. GRIFFIN: And will be bringing that back to the Committee, and the product in the early spring.

MR. SKOWRONSKI: All right, thank you.

MS. BAKKER: Actually now that surprises me because what it looks like in David's graphs is, and maybe I'm just not understanding it, that you've used the estimate of revenue streams to decide what additions to add. And that that's where we got 2007 through 2013. And that you've already added your resource plan.

MR. VIDAVER: I've added the resources, well, I proposed a decision role to add resources based on 1998/1999 reserve margins. But the impact, or the results of that assumption, as Mr. Arthur said, still need to be tested. And that's the purpose of doing the scenarios.

We have not looked at the profitability or lack thereof of specific power plants. For example, the generic combined cycle. We haven't looked at the prices in say 2009 and said, oh, combined cycle could make money this year, so we'll add one. We have not done that type of analysis.

MS. BAKKER: Okay, well, what's confusing then is the two slides following this which actually show additions from in California and in the rest of the west.

MR. VIDAVER: Yeah, these are the capacity additions necessary to sustain reserve margins at the 1998/1999 levels. So if we're going to decide --

MS. BAKKER: Okay, so you actually do have a number then, don't you?

MR. VIDAVER: 4,065, yeah.

MS. BAKKER: No, no. Percent.

MR. VIDAVER: Oh, do I have any idea what the reserve margins are?

MS. BAKKER: Yeah.

MR. VIDAVER: Yes. Do I have a number written down right here that I'm going to share with Commissioner Keese?

(Laughter.)

MR. VIDAVER: No. No, I got the impression that the Commissioner was asking for some number between 7 and 30 that I knew. And to be quite honest, I don't. I don't know what the reserve margin was, off the top of my head. I could go calculate it, and then say what it is, and watch everybody debate whether or not that number was indeed accurate.

MS. BAKKER: But it was the 98/99 number?

MR. VIDAVER: Well, yeah, that I think is a relevant number, but it's not one that I can -- if I said 24, pulling a number out of the air, a good share of the audience would probably go 24? Oh, that's way too much capacity. We don't need that. Deregulation must have failed.

And if I said 7, I imagine people would

come running over from the Power Authority en masse and say, oh, we can't live with that.

So, I hesitate to say what that number was. Because even though we can calculate it, it has an emotional content that there are different ways to calculate it, and --

MS. JONES: So, just to clarify what we've got up here, did you just basically take demand or peak demand and then subtract out what you've got in the system and the retirements and all to come up with these additions? This is just a simplistic assessment and it doesn't have -- well, it has an implied reserve margin?

MR. VIDAVER: Yeah, that's exactly what we did.

PRESIDING MEMBER BOYD: I appreciate what David's saying and we don't want to debate on the number. He's right, he'd become a target suddenly. But now everybody's going to run out and back-calculate based --

MS. JONES: Yeah.

PRESIDING MEMBER BOYD: -- their '98 --

MS. JONES: Because I could do that calculation.

MR. VIDAVER: But they have to use our

numbers. That's --

PRESIDING MEMBER BOYD: But at least they'll do it outside of this room, and debate with themselves. And I appreciate the weaknesses and strengths of the years '98 and '99. My first, I mean it was the heat storm year, was this, that and the other, but absent a lot of other testimony, you know, and greater -- probably for an academic discussion, a halfway decent place to start.

I just want to comment on something that was stated earlier, thought, in that debate about the 98/99, and that was well, that couldn't have been a good reserve margin because the sky fell on us shortly thereafter. Well, the sky fell for a lot of other reasons.

One of the issues we face now, since we came out of a regulated monopoly where you dictated and assured what the reserve margin would be, and lots of people in the state thought electricity was too expensive in California, among all the other reasons for deregulating.

We're now in that hybrid area of trying to figure out, you know, who will pay, and how do you pay for adequate reserves, and once you set a target. So that's another policy dilemma that a lot of people are still trying to deal with.

But the people who are dealing with that, including this organization, are the people who are trying to rebuild the ship that burnt to the waterline, and decide where to set sail next time around.

I keep thinking of that Viking King who built the most magnificent warship ever seen, and kept changing it. And his people didn't have the courage to tell him he was maybe, you know, all these changes he wanted might not go. So they built the ship and they set sail and it sunk in the harbor. And they dredged it up here recently. Now it's a great display in Stockholm.

But, I mean that's the same committee who built our restructuring thing, I think. Anyway, I don't want to get off on that.

(Laughter.)

PRESIDING MEMBER BOYD: David, you don't have to keep defending yourself. I appreciate your dilemma here.

MR. DeSHAZO: I'm Gary DeShazo with California ISO. And maybe perhaps the conversation has sort of moved beyond where we were when I first got up. But, since I made the effort --

PRESIDING MEMBER BOYD: No, it's relevant.

MR. DeSHAZO: -- I'll go ahead and --

PRESIDING MEMBER BOYD: Please do.

MR. DeSHAZO: -- there were a couple of questions that were asked. The ISO, you know, sort of continues to come up in the conversation. And that's a good thing because that's what we want to have happen.

But I think that maybe going back to a comment that I heard you make a little bit earlier about the balance of the resource against the transmission. And then the comment that you had made about, well, maybe we should just not assume any transmission building at all and see what the resource would be about that.

And at least in my mind, from a perspective of trying to find the best way to make sure that we have a reliable system, and that we can serve the load in our state, it's really the balance between those two.

And I think that what has just occurred in the discussion is what has always been the basis of that conversation is trying to figure out how that is done.

Now, we've got a planning process. You've got a resource acquisition process. You've got a load forecasting process. And in my mind I think the real question is how do those things get matched up, so that what you end up with is something that is worthwhile, is buildable, and at a reasonable cost.

I think that's the overall key. And at least from the ISO's perspective and the process that you're getting started here, I guess, we view that as a way to start that conversation and see where things end up. And so provide us the opportunity for the input and we'll see where things go.

But that was the comment that I was interested in making at the time the questions were asked.

PRESIDING MEMBER BOYD: Thank you.

CHAIRMAN KEESE: Let me ask one question. You're talking about this is the additions to demand?

MR. VIDAVER: These are --

CHAIRMAN KEESE: Or are you -- is this

what has to be built in those territories?

MR. VIDAVER: This has to be built in these areas to maintain reserve margins at 1998/1999 levels.

You can see that we're --

CHAIRMAN KEESE: And are you assuming historic import factors?

MR. VIDAVER: The reserve margin calculation that we're doing excludes imports from consideration. It's still on the ground in California or owned by California entities outside the state.

CHAIRMAN KEESE: Okay, so for example, if you need 500 megawatts in the Southern California Edison territory in 2008, it might be built in Arizona?

MR. VIDAVER: No. We're assuming that the reserve margin is based on steel in the ground at that location. So, when I say 150 megawatts in Southern California Edison in 2007, that's where the plant is being built.

Now, remember this is an assumption for a simulation, a computer-driven simulation. In reality, that 150 megawatts could be provided by a plant in Utah owned by a merchant generator who has a 150 megawatt 7-by-24 firm contract with Edison. In reality.

So, one --

CHAIRMAN KEESE: Okay.

MR. VIDAVER: -- one of the caveats about this is that the reserve margin, several caveats, but one is that the ultimate reserve margin is going to depend on, for example, the extent to which regulatory authorities allow contracts from out of state to meet resource adequacy requirements.

Another caveat is that should regulators allow, be flexible in determining what resources can be used to meet resource adequacy requirements. Capacity can be built well outside the state.

As the gentleman from the ISO just stated, if the incentives exist to expand the transmission system, and we have a transmission pricing scheme which incents building generation in remote areas, and using wires to get the power to load centers rather than gas pipelines, you will have a much different set of resources being added than you would had you encouraged -- had you adopted, for example, another transmission pricing scheme, or not expanded the transmission system to the extent that you would have liked. And forced or incented generators to be built next to load centers.

So, this is a very very simple rule of thumb that can, in a geographic, can vary dramatically depending on regulatory outcomes that we have no knowledge of.

CHAIRMAN KEESE: I guess I'm comparing it to my very simple thumbnail rule that we need about 2 percent more a year so that's somewhere in the area of 1000 megawatts a year.

MR. VIDAVER: What you see here is you see the 1000 megawatts a year starting in about 2009. This is indicative of the fact that given the capacity that we've added to date, and the capacity that we expect to be added today and the capacity that we expect to be added through 2006.

There won't be a need for any in 2007 and '8, at least to meet the reserve margin criteria that we're using as a decision rule.

CHAIRMAN KEESE: Thank you.

MR. TOMASHEFSKY: That's right. Now from a policy perspective the question then becomes given if that's the profile we need, what happens that might affect whether we can get that in the first place. And then that's where we run into the situation where you choose a different reserve margin estimate, whatever that '98 or '99 number is. You may need considerably more and you may not have the policies that would allow that to actually occur. So that's where this number then becomes important.

MR. VIDAVER: Yeah, certainly the higher the reserve margin you need, the, in some sense, the more dramatic the set of policies you need to achieve it. So, in that sense, yes, that's certainly true.

MR. KELLY: Yeah, I just have a general question -- or comment, actually. It kind of feeds off from my comment yesterday when we were talking about the demand, and I think it builds off what Commissioner Boyd was talking about.

Yesterday we were talking about demand and how do you treat committed demand and noncommitted demand. And the question that I had really was how do you know something is committed or not committed.

And I think one of the things in developing a baseload, the baseload from which we will develop scenario studies to drive the policy decisions, the baseload planning, what I think is missing in the report is, in my mind at least, is clarity about what are the standards or the criteria to determine if something goes into a cell that generation is going to be there, or demand will be there.

I get the sense I'm being asked to comment, for example, is there going to be 800 megawatts geothermal. I have no idea if there's going to be 800 megawatts of geothermal. If you ask me to comment should you include it in your study that we're going to count it as committed once they've filled an AFC, then I can respond to that. And I can answer yeah, that makes sense to me. And we shouldn't do it off a letter or a phone call from some guy out in, you know, south Burney.

Those kinds of things and those standards and criteria for determining how you're treating the indiscrete -- there's discrete variables is something that I think is missing here. And I'd like to see maybe a chapter or some place bring that out so that it would make it easier for stakeholders to comment that is reasonable or that is not reasonable.

And then those factors will drive, I think, whatever numbers are fitting into these cells. And quite frankly, it's very impossible for me to respond to what in the cells, but I can talk about factors and whether it's reasonable or not.

I'd recommend you thinking about structuring the report to do that on the baseline. And then the next step would be all right, let's do some scenario planning that's going to drive policy decisions. What if you do this or this? Do we have enough capacity to meet a preferred reserve margin.

That's kind of how I think this report process might be helpful over the next four or five months if we get a good understanding what the baseline is.

Just a comment.

PRESIDING MEMBER BOYD: Well, I think it's -- I appreciate the comment. I mean when I got done reading all this and trying to understand it I kind of felt like this is going to be a tough couple of days, because we have half a loaf.

And we've already talked about we're

going to provide the other half of the loaf a little later down. And then have everybody back.

This is not meant as a criticism. It's taken all the bakers that we have at our disposal in this organization to get us this far. And I think the workshop is proving extremely valuable.

The staff is trying to -- and we, we're trying to tease out of the experts in the audience any of those factors and points that should be included as we move farther down the line.

And then the next time we have a workshop I think we'll have a more mutually educated view of where we're going.

But I mean, we have to do what we do and it's tough. I mean this is a tough couple of days to deal with this because we aren't dealing with everything out on the table. And the staff is, I think, trying to get as much help as they can from all of you. And I'm sure each successive day there will be more and more interaction with folks, vett some of the assumptions and what-have-you.

But we are crying out for help in terms of your knowledge and views of this issue. It's been a long time since people sat down to do this, I'll bet, if anybody's tried to go as far as I think this conceivably could go, after surviving the wreck of the past couple of years. So, in defense of where we're trying to go.

I agree with the gentleman from the ISO. When we get all done we have to plug this back into some system that is kind of -- I know models are good tools; I like models for tools. But, god, we depend on them to make decisions that they can't make.

But, nonetheless, we have to establish all the various criteria parameters and try to get them as much agreement on those before finally cranking out the system to balance the system; do you do transmission, do you do generation, policywise, how much self gen, cogen can you tolerate. All of this in the environment of we have a mortgage to pay off, and rules and regulations relative to making sure we pay off that mortgage.

So, et cetera, et cetera. As we keep adding more factors this is going to get even more difficult, and David's life is going to be even more challenging, let's just say.

And I want to -- I just want to comment

at this juncture that I'm appreciative of the fact that we have advisers up here with us. My Adviser, Susan Bakker; Scott Tomashefsky with Chairman Keese, and particularly Melissa Jones who is sitting in for Commissioner Geesman, who is intensely concerned with and involved in the transmission question. And would have sat here with us, could he have, and I appreciate the fact that Melissa is here watching out for the transmission piece for us. Because it is part of the three-legged stool that this thing's going to sit on. Transmission, generation, et cetera, et cetera, so, anyway, must be getting close to lunch or something.

But, David, you have to finish.

MR. VIDAVER: I have to finish -- I was going to try and address a couple of Mr. Kelly's concerns beyond saying that I think it --

PRESIDING MEMBER BOYD: How much more time do you need, David?

MR. VIDAVER: Probably, to do it justice probably a little more than our stomachs will allow.

PRESIDING MEMBER BOYD: Twenty minutes? Half an hour? An hour?

MR. VIDAVER: Okay, well, you throw me out of the room when you get tired of listening to me.

PRESIDING MEMBER BOYD: Do you need 20 -- can you do it in 20 minutes?

MR. VIDAVER: Twenty, probably. I'll -- yeah, if people don't interrupt, yeah.

PRESIDING MEMBER BOYD: It would be nice to finish.

(Laughter.)

PRESIDING MEMBER BOYD: All right, it would be nice to finish this rather than break in the middle.

MR. VIDAVER: Yeah, okay. Just quickly I want to respond to what Mr. Kelly said. As far as the short timeframe in which we have a reasonably good, yet not nearly good enough feel for what's going to transpire, I think scenario analysis is -- we do a baseline where we put in Otay Mesa and Metcalf, and then we yank it out, because it's quite plausible that it won't come online, and we see what happens.

In a longer run when nothing is committed as of right now, we have to use a set of rules for devising a baseline. And the presence or absence of commitment certainly can be one of them, as I'm sure you'll agree.

Going back to what Dave Arthur said, maybe what we do is we adopt a set of decision rules and then see how sensitive the adoption of that rule is to, you know, can we deal with a drought and a heat storm in one year if we make this set of decisions. Even answering that question is taking a long step forward and useful in deciding whether or not you've actually come up with an appropriate baseline.

These are the California additions that we assume. These numbers are not final. We're going to be tweaking them. Most likely we're going to move capacity out of I should say SP15, and into NP15.

So the total quantity is probably pretty accurate, but we're going to, as we do simulation runs, and look at the results, we're probably -- my guess is we're going to move some capacity out of southern California and into northern California. We're seeing a price differential between the two regions with this set of additions that we're not real fond of. And one that we don't think the market could sustain over a long run. People would build capacity in northern California with those price differentials.

A set of capacity additions for the remainder of the WECC. What they indicate is that the southwest has done a good job of paving itself over. And the northwest has not. The Northwest Power Planning Council sees itself as possibly being short; having unacceptably high possibilities of curtailing load in 2006/2007. And the numbers that we come up with for capacity additions there reflect that concern.

So Baja, California is another area that we would like advice on. We expect that that region is going to grow substantially. But the amount of capacity being added there is quite substantial. We're not sure that 500 megawatts is apt to be all that we see down there over the next ten years, even if that gets us back to an adequate reserve margin. Or back to a reasonable reserve margin, I should say.

Not so loose ends. We would like some input on how to -- when we add new capacity we have a choice of the type of capacity to add. And I'm not really referring to renewable, nonrenewable. We do need to refine our assumptions about renewable non-RPS capacity that's liable to be added outside of California. PacificCor in their resource plan said they're looking to subscribe to anywhere between 500 and 2000 megawatts of wind capacity that does not exist in the northwest over the next several years.

We do not assume that that amount of capacity is going to be added, and we should. The reason we don't assume that is, one, we don't have very good information on the resource development potential in the northwest and he likelihood that large amounts of wind capacity are going to be added.

The second reason is we don't know how wind generators in the northwest perform. We're talking about confidential data. We do know that they don't perform with a seasonal and daily profile that they have in California. That they're far less cyclical. But there is a dispute as to how efficient new wind turbines are in the northwest. The statements of developers seem to be optimistic compared to the real live performance from existing wind units in the northwest and we want to resolve that difference before we explicitly model new renewable capacity there.

What this is referring to is do we add baseload or peaking capacity. Because we are not using a methodology which is amenable to screening curves and analyzing revenue streams of generic new combined cycles and peaking units, we need to come up with another way to say, okay, enough baseload, we should be adding peaking capacity.

And what we propose to do is establish a sort of threshold capacity factor for combined cycles. And once the new combined cycles in a transmission area reach that capacity factor assume that one more combined cycle would not be built because it simply would drive the capacity factor of the other plants too low. And all incremental capacity added in that area be peaking capacity.

If anybody has a suggestion as to another way to look at this, another way to make this decision, speaking to the modeling nerds, please let us know.

And the biggest concern. The state, as everyone is fond of pointing out, has a lot of very old capacity. It's not as old and not as dispensable as people would like us to believe. There's been a substantial number of repowers. Operators obviously anticipate going forward for some time. At least those who have installed SCR. Some older plants actually have RMR contracts. Some actually have DWR contracts.

So, the notion of which plants are apt to disappear presents a series of difficult questions. And staff hesitates to unilaterally retire large quantities of capacity simply because it's old, and simply because it's inefficient.

However, we do realize that this is going to take place. From a modeling perspective, and I know those of you who aren't modelers will find this difficult to believe, it really doesn't matter. Because when a plant gets inefficient enough it just sort of stops running.

And if you can imagine a 1500 megawatt behemoth acting like a peaker that just can't quite respond as quickly but nevertheless it's only used during the summer, a prolonged exposure in a modeling environment sort of absolves you from having to make these decisions.

Now, what failing to retire these plants does is it makes, well, one thing it obviously does is excuse your reserve margin. So if you're using that as a criteria and you decide whether or not to add plants, your inclusion of aging capacity reduces the amount of new capacity that you add. However, what it does do is -- or what it doesn't do is affect that capacity factors of those new plants.

So, in a sense, if you're looking at about 8000 hours of the year it doesn't matter whether you add or you retire aging capacity.

Unfortunately, when you look at the other 400 to 800 hours your decisions about what plants to retire are affected.

So what we would like from the modeling community is some assessment of is it necessary to adopt a decision rule regarding the retirement of older capacity. Can anybody, like somebody's actually set foot in a 50-year-old power plant, tell us what power plants are apt to retire or not. We think we have -- we know which criteria we should be looking at to make that decision.

How much capacity we should retire. What capacity we should retire. And what we should replace it with. The logical alternative would seem to be given that most of these older plants, if left in service, will basically become peaking units, is simply to replace these plants with gas turbines with LM6000s that have roughly the same heat rate as older steam turbines, but operate much more efficiently, that can ramp up and ramp down much more quickly and respond to prices much more quickly.

So, we realize that the assumption that nothing is going to be retired is a contentious one. And we want to acknowledge that our simulations might be more plausible, if not dramatically different, if we retire some aging capacity. And we'd like some input as to how much of that should be retired and what it should be replaced with.

And finally, if you've read our document from the 13th you've seen that we proposed a number of scenarios. Many, if not all, of these feed into other work that the Commission is doing. All, to some extent, allow us to assess the sensitivity of market conditions and such indices as reliability and price to the underlying assumptions that we made.

The first scenario is that we don't build Otay Mesa; we don't build Santan. A large share of these plants do not come online. The economy booms. We find ourselves in the middle of, at the peak of the business cycle in 2006 or 2007 and it doesn't rain. This seems to be a scenario which would test the ability of the system to deal with adverse conditions three years, four years down the road, under what is not really worst case scenario, but a very plausible one.

We'd like to look at high and low natural gas prices. We want to test the affect of these high and low prices to bound the financial risk that we face. To be honest, high gas prices and low gas prices are not really going to affect how individual plants function on a daily basis. They will affect how much renewable capacity is added in all probability. The higher gas prices get, the more likely we are to see renewable capacity, the more likely we are to see RPS targets not only met, but exceeded.

But more importantly, these numbers are important to us because they indicate how much financial risk we're at. The major risk California faces right now, given that we have a capacity surplus, albeit only a small one, and albeit only temporarily, is financial.

Right now gas prices are sitting at Henry Hunt at $19, the southern California border they're sitting at 9, this has implications for the cost of electricity and the money that comes out of ratepayers' pockets.

We want to look at adverse hydro conditions in a booming economy in 2007, '10 and '13. Hopefully this will, to some extent, address Mr. Arthur's concerns, that if you build out to a 1998 or 1999 level you're still at risk of -- you still face a substantial amount of reliability risk, an unacceptable amount of reliability risk.

We also want to look at reduced renewable capacity over the 2007 to 2013 timeframe. Let us assume for whatever reason we don't realize the amount of renewable capacity that would allow us to meet RPS targets, what would be the implications of that. Mostly negative for prices for the environment, et cetera, et cetera.

Finally, we want to look at a case where there's a substantial amount of investment in efficiency and/or conservation and/or an increase in the amount of cogeneration where people basically go off the system, and increased amount of self generation, and increased amount of distributed generation.

With slower load growth we have -- we reap several benefits and we'd like to be able to quantify that.

So, those are the scenarios. We are welcome to doing more of them. Keep in mind that we're under kind of a time constraint as Commissioner Boyd has so graciously acknowledged.

And I think the next slide is black. Oh, all these questions.

MS. JONES: Before we go on to the questions, in terms of the scenarios, have you thought about doing a faster load growth and looking at more self gen, distributed gen and increased efficiency as another scenario?

MR. VIDAVER: No. The combination of those two would leave you right back where you started, I think. If the economy boomed and all of a sudden industry started locating in California at a more rapid rate than expected, and then you offset that with people putting PV on their roofs and industrial concerns going offline, you'd sort of end up with a baseline.

In choosing the variables to look at we wanted to look at things that reinforced each other rather than offset each other. And at the same time we wanted to looked at a limited number of things so we didn't drive the implicit probability of the scenario down to zero.

We didn't want to look at, for example, a faster load growth, adverse hydro conditions, and two or three other variables, all of which serve to stress the system when the probability of all those things occurring simultaneously if you were -- so, I'm sorry. I've had too much coffee.

MS. JONES: Yeah, I just think that implies some judgments there that might not reflect reality. I mean, I can envision a scenario where self generation and increased DG are very good ways and very cost effective ways to meet high demand growth, so.

MR. VIDAVER: Yes, and I fully agree. The first variable that you mentioned was faster load growth. So faster load growth, for macroeconomic or demographic reasons, would result in high load growth.

And then if you took that off the system by saying you encourage efficiency and distributed generation, et cetera, you would get the load growth sort of back to where it was in the baseline. And that's something that we want to avoid.

MS. JONES: I still don't understand that line of reasoning, but --

MR. VIDAVER: Sorry, I may have misheard you, I'm sorry, Melissa.

We have panelists, and here he is.

(Laughter.)

MR. MELDGIN: Thanks for letting me know.

MR. VIDAVER: Mark Meldgin of PG&E was gracious enough to agree to comment extensively on this, but I don't think we have -- perhaps it can wait until after lunch or something. But any questions --

MR. MELDGIN: That's what I was going to ask. I want to bring up something that is going to take a fair amount of time. But, on the agenda I see scenario considerations for risk studies starting up after lunch. If that's correct, if you're going to be here after lunch, I'll put it on hold.

MR. VIDAVER: That is up to Commissioner

Boyd.

PRESIDING MEMBER BOYD: Yeah, I think we'll break now. You might want to put your questions up there for people to see and think about as they're eating lunch. But after lunch we have some questions to consider, and this presentation. But if everybody's picked up your presentation in the back on the table in the entry, why they have your questions hopefully.

So we'll come back here at 1:30 promptly, please. It's going to be a long day.

(Whereupon, at 12:25 p.m., the workshop was adjourned, to reconvene at 1:30 p.m., this same day.)

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AFTERNOON SESSION

1:30 p.m.

PRESIDING MEMBER BOYD: Get the train back on the track. David, we left you leaving the audience with questions. And also we had people to make comments. So, let's pick up where we left off.

MR. VIDAVER: We left off with Mark Meldgin standing at the podium.

PRESIDING MEMBER BOYD: Right.

MR. VIDAVER: I don't know if he wanted to -- do you have all your questions successfully answered offline?

(Parties speaking simultaneously.)

MR. VIDAVER: We invited members of the energy community to sit on a panel. As you know, this is one of several reports and there are separate panels for each report.

For whatever reason, and I hesitate to dwell on it for too long, we didn't really get much of a response, other than Mark. But we don't really want to sit him up there ala William Buckley and have him pontificate. But he is an incredibly bright guy with a lot of observations; and he's done modeling for years. So, he can either say his piece now or wait; it's his call.

PRESIDING MEMBER BOYD: Well, he was on his way; let's let him finish the trip.

MR. MELDGIN: Well, I wanted to get to a question that came up briefly, and it's maybe a second-order question, but it's the question of whether to build transmission lines or to build gas pipes.

You mentioned that there's the option of putting the gas-fired power plant near the gas supply basin or the LNG terminal or whatever, and then bringing wires to bring the power to the load center. Or build a gas pipe and putting the power plant near the load center.

There's maybe four important aspects of that question, at least four. One is which overall is cheaper; which is more reliable in terms of serving the electric demand; which is more secure for the issues that the Commissioners raised earlier today; and which is likely to happen in the absence of any strong attempt to change things.

So I was just wondering where the staff stands on those things, those issues.

MR. VIDAVER: Where the staff stands.

Okay, that makes it a little easier. A person who is more qualified than I am to answer these questions, or certainly whose input I would like is Bill Wood on these issues.

I think that it's generally acceded right now that it's cheaper to build the gas pipeline. I mean I don't think that Bill -- he's not standing up and screaming but that's because he's not here.

I would defer to Commissioner Boyd regarding security. I don't know whether it's easier to blow up a gas pipeline or a 500 kV. I don't --

PRESIDING MEMBER BOYD: I don't want to answer that question in public.

(Laughter.)

MR. VIDAVER: What is more likely? I think we can all generally agree that building pipe is certainly more likely. It has a much shorter lag time, lead time, whatever is appropriate. It's just much easier to do.

The regulatory jurisdiction, the jurisdictional issues have more or less been resolved, I believe. So, and reliability, well, yeah, gas pipelines don't tend to be derated with the frequency that transmission lines do. So that's my answer.

MR. MELDGIN: I'm real surprised by one of those, which is which is more likely to happen. Because if it's any kind of a merchant developer looking at least cost, there's some chance that he'll have to pay for gas transmission on the basis of some sort of charge per mile; whereas, on the electric side there's a chance that society, as a whole, will bear all of the costs of the transmission upgrades, and possibly even some of the losses.

MR. VIDAVER: I misunderstood your question. I was answer the question which is easier to site.

MR. MELDGIN: Oh, okay.

MR. VIDAVER: Now, you're answering a different question, and I have no doubt that you're right. Simply --

MR. MELDGIN: I have doubts that I'm right.

MR. VIDAVER: -- because you're you --

(Laughter.)

MR. MELDGIN: All right, that was all I had, thanks very much.

MR. VIDAVER: Thank you.

MS. JONES: Well, I think one of the important issues associated with that is rather than shooting from the hip, to actually look at the different costs associated with all of the different options and try to compare them on as comparable a basis as possible.

MR. PRUSNEK: Hi, my name is Brian Prusnek from the California Public Utility Commission. And I just had a question. I was wondering when we say build more gas pipelines for power generation, are you referring to building interstate pipelines, or increasing the amount that we have instate?

I was kind of missing the point because I didn't think there was a direct, you could compare building wires versus building pipes. I didn't see that as an easy choice. Maybe if you could expand on that?

MR. MELDGIN: Well, this actually brings up a comment I maybe should have made about the reserve margin approach you're using. An alternative scenario would be that generators decide to build where gas is the cheapest. And based on what little I know about gas markets and so on, that would probably be southern California, because there's the cheap Rocky Mountain's gas coming down via the Kern River pipe. There's the potential for one or several LNG terminals in Baja.

So, one possible alternative scenario would be assume the same total number of megawatts get built, but assume that the bulk of it happens down near the lower Colorado River; and then the transmission has to be expanded to get the power into northern California, rather than assuming that the new growth is distributed nicely and evenly around.

MR. VIDAVER: Yeah, I believe, perhaps with a lack of clarity, I did say that the geographic distribution of power plants, even if they sort of met this reserve margin criteria, the total amount of capacity in aggregate was the same. It might be distributed geographically much differently.

You're pointing out that it's liable to be near an LNG terminal in Baja, for example, or on Kern River or someplace where gas is very cheap. That's a -- we'll certainly talk that over with Bill Wood and Jairam Gopal. And I have no doubt that they'll encourage us to develop that scenario.

MR. MELDGIN: Okay. And then getting back to the question for the gentleman from the PUC, then that's really the issue. It's, you know, I don't care whether it's interstate or intrastate, but if these plants get built near the Bay Area, then it's the possibility that the pipe will have to be expanded to get the gas there.

You don't need to do that if you build all these power plants down in the lower Colorado River. But then you probably have to expand Path 15 and maybe some other stuff.

MR. VIDAVER: Thank you, Mark.

Is that it?

PRESIDING MEMBER BOYD: What's the term? Least cost best fit?

MR. VIDAVER: That's the term. And I think there are 42 definitions of that in Webster's Third International.

MR. ABELSON: Is it appropriate now to make some comments about some of the specific assumptions?

MR. VIDAVER: Certainly.

DR. ARTHUR: Well, one, on the transfer

capability between the northwest at NP15 I think you had a number that is probably correct as it relates to the nameplate, but I think it's high relative to what is typically available on any given day. So that might be something where talking to the ISO would be helpful.

But my recollection, not being a transmission planner, is that 4200, 4000 is a closer number that's typically available.

A question I didn't understand from the material presented was in the supply numbers that you provided, does that include an allowance for forced outages, or is that essentially nameplate?

MR. VIDAVER: Neither. It doesn't include forced outages, but it's derated, for example, for high ambient air temperature during the summer --

DR. ARTHUR: Okay.

MR. VIDAVER: -- if it's located inland, et cetera. So, it's sort of dependable, but doesn't include a derate for forced outages.

DR. ARTHUR: Okay. And along that line, one possible thing to consider when you're dealing with the aging of the plants is simply to change the forced outage rate which may give you a way of indirectly adjusting for that possibility.

MR. VIDAVER: That's an excellent idea. Although if we make the forced outage rates any higher on some of these older plants, we'll effectively be retiring them.

Okay, that's a great suggestion.

DR. ARTHUR: Well, from a modeling point of view it may just a way to backdoor, where it doesn't require horrendous outboard efforts.

MR. VIDAVER: Yeah, a heroic sets of assumptions. That's a very good idea. We contemplated the increasing of forced outage rate uniformly on some units to deal with the notion of capacity withholding at one point.

DR. ARTHUR: Another question I had was in the aggregation of the megawatts of capacity did that assume that some of the renewables are 100 percent available during those peak periods, or did you adjust for --

MR. VIDAVER: Wind is given -- we've had internal debates about whether the value of wind was zero, 5 percent or 10 percent.

DR. ARTHUR: Okay.

MR. VIDAVER: The answers to that question are sort of as much political as they are engineering --

DR. ARTHUR: Right, and I would prefer to stay away from that.

MR. VIDAVER: Yeah, so would we. But geothermal and bio --

DR. ARTHUR: And then I would lastly like to introduce a concept that I thought about over lunch to decide how it was most appropriately introduced, and I've come up with the term friction out of the concept of physics to discuss the idea that what we've presented to this point, I think, is without friction.

And I think there are such things as regulatory friction and institutional friction that when you allow for those results in the actual reality being usually less robust than what the raw numbers might suggest, so as we progress it seems like we ought to have some sort of friction coefficient that would allow for those kinds of impediments that seem to evolve over the course of time.

And lastly, I just wanted to commend the good work. I mean, I have been slightly critical and I apologize for that, but the work is very helpful to small utilities like Redding, having this quality of work and this kind of data available for our own internal understandings is invaluable, because we would never be in a position where we could put something like this together, ourselves. And we're very appreciative of the work that's being done and the opportunity to participate.

PRESIDING MEMBER BOYD: Thank you. I think least cost best fit just got modified by after clearing lots of hurdles.

MR. VIDAVER: Anyone else? Anyone in this room feel free to -- Mr. Miller. I wasn't serious.

(Laughter.)

MR. MILLER: Well, let me ask about a process here, in that were you going to call panelists up or --

MR. VIDAVER: To be honest, I was under the impression that Mark was the only person who had agreed to sit on a panel. That we had solicited other entities who shall remain nameless, and not received a response.

And Mark was the only person who did. So my proposal was just to, if you have extensive comments, feel free to stand uncomfortably at the podium and make them.

But if you'd prefer to constitute a panel of one or two or --

MR. MILLER: Well, what we have is actually a team from PG&E that has, for different parts of the report, I mean the transmission or gas infrastructure, as well as when you go on to the cost competitiveness of the generation.

So I'm not sure what the timing is for that.

MR. VIDAVER: I'm not running this show. Al, do you have any suggestions about how we should handle this?

MR. MILLER: Myself, I had comments on this last.

MR. VIDAVER: Perhaps --

PRESIDING MEMBER BOYD: I was going to say perhaps, unless your presentation fits together -- better together as one piece, it might be better just to give your comments now on what we've spent all morning on. And then get the gas presentation and have your gas person, or whatever combination, two or three folks you might want.

MR. ALVARADO: We are going to have presentations by Judy Grau and Mark DiGiovanna.

They're going to talk about transmission and gas issues, too.

So, if you prefer to wait after each of the speakers, or --

UNIDENTIFIED SPEAKER: (inaudible).

PRESIDING MEMBER BOYD: Well, let's do it that way. Let's go with the generation because it will be too long an interval between things. And so, if you've got comments now, go for it. Or you and your team. Or, you're the team.

MR. MILLER: Bear with me here.

MR. VIDAVER: That is only one sheet of paper, right? Okay.

MR. MILLER: First of all I want to, you know, thank you for the opportunity to share my thoughts on this. And in particular, thanks to David Vidaver who helped walk me through a lot of the approach, the methodology that they're using for their studies.

And overall, you know, the assumptions across the scenarios, I think provide a reasonable framework for the current trends of supply and demand. And I think the CEC has done a very good job of identifying the key issues that the California energy industry faces going forward, you know, the financial market, credit risk problems, reasonableness and regulatory risks, transmission pricing, the problems of the illiquid market and the need for developing a new market structure and planning processes which come along with the reserve requirement, and price cap issues and all those things.

So where I'm leading is if the objective of this effort is to use the findings from these studies, from the baseline study and the scenarios, to develop policy and shape the industry going forward, it's crucial to define the scenarios to frame the key issues that you want to bring forward.

So that being said, one of the big concerns I have is that my belief is that the industry is very capital intensive. And on the topic of reserve margins, in particular, using the '98/99 reserve margins may have been a period where reserve margins were pretty high.

And there's been a lot of different suggestions for different reserve margins going forward; anywhere from, for example, the FERC, you know, 12 percent minimum; I think the PUC has a 15 percent; California Power Authority 17 percent.

So, the high reserve margins can, you know, reflect an over-supply condition, you know. For example, if you were to build out, you know, 50 percent reserve margin with combined cycles, I mean that would really flatten out the volatility of prices and stuff. But there's a cost for doing that.

And so I think it's important to quantify the cost of carrying this excess reserve. So the point is the reserve margins requirement may have a significant impact to the supply curve, and ultimately to market prices.

So this leads right into, you know, uncertainty in market prices. This is going -- the reason I bring that up is that same period there was fairly low prices in the 98/99 period. And may not have been that attractive for new investments.

The crisis happened. A lot of generation did come on, and as a result of that, prices came down again in 2002 by a good margin. So, --

CHAIRMAN KEESE: Actually, we released a study -- when we released the heat storm study in '99 we also released a study saying that the market dynamics were not there. That if you built a power plant you would lose money. And that's what would have happened in '99 and 2000.

MR. MILLER: Right. So, you know, going forward what I think needs to be captured is the tradeoff between the cost of reserve margins, you know, versus the market price of energy. You know, you can have one choice to be to have a high reserve margin and less volatility perhaps on your supply curve. Or the tradeoff would be go with the less cost of having a lesser reserve margin and maybe more volatility on your price. But there's a tradeoff there. And I think that's something that we could probably, you know, maybe in the scenarios, quantify.

In addition to the market prices that are calculated, I think it's imperative that you bring up the payments, the revenue, you know, the capacity costs, payments for ancillary services, and all those other flavors of revenues that would go towards covering the fixed costs and capital investments of new generation. Because, again, to get the right understanding of the price of power you need to do that. Okay.

So I have a couple suggestions for

scenario enhancements. One would be perhaps you could put this into the high load growth and fewer additions is to maybe go with the -- study the impact of a lower target reserve margin of, you know, whatever number it is, 12, 15 percent, in comparison to -- okay.

MR. VIDAVER: You said to look at that in the context of higher load, lower adds.

MR. MILLER: Right.

MR. VIDAVER: So that effectively would be a lower reserve margin compared to the baseline. And what you're suggesting is that we look at the financial consequences of --

MR. MILLER: Yeah, the impacts to the market clearing prices, et cetera.

MR. VIDAVER: Okay.

MR. MILLER: And the second scenario, I think it's important -- this is what Mark was leading to -- is the location of the generation, I think, is a big thing.

And we talked about the planning reserves, and maybe doing, on one side doing it on a service territory basis, building out to meet the reserve requirements versus on a statewide basis or a broader regional basis, and have, for example, the siting of generations closer to the interstate gas pipelines or wherever and --

MR. VIDAVER: As Mark suggested.

MR. MILLER: And then, again, you know, those costs of the different scenarios should be rolled forward in the analysis to see what is the least cost most benefit.

Another point or suggestion is maybe, you know, from analyzing the viability of the new generations, or the generations on the margins, setting the prices is to sort of use a balance or income statement approach where, you know, you determine the cost effectiveness of the resources by looking at the revenue streams from the market prices to see what costs they are recovering, and if they're recovering a reasonable rate of return.

MR. VIDAVER: What would be the goal of looking at that? The difference between what they need to recover in the energy market --

MR. MILLER: Well, it can be useful in numerous ways. One, it can, you know, on the long term if, for example, on the 2007 through '13, if you're trying to mimic a market in an equilibrium you would assume at that point that -- let's say for example, a combined cycle, would be making their targeted rate of return, whatever that is defined as.

I think that would be -- you'd want to see the capacity factor and those things realized, as well, from new generation.

On the other hand, you know, from the retirement units it could be useful and instructive to adjust their costs of operating. Maybe they discount, you know, maybe they don't have the capital costs, maybe they're already, you know, they could go forward just on operating costs or ongoing forward costs and could discount and maybe become more competitive or extend their competitiveness.

MR. VIDAVER: Yeah. One of the problems with the latter is that we do not have access to the information that allows us to adequately or accurately assess going forward costs for existing facilities.

So, that's something we might have been able to weasel out of you ten years ago, but we certainly can't get it out of Mirant and Reliance, so.

MR. MILLER: I realize that's -- you could make some, for example, you know, the fixed costs. You know, you could maybe make an assumption.

MR. VIDAVER: Can we come to you for some best guesses as to what those going forward costs might be?

MR. MILLER: Perhaps we could discuss it.

MR. VIDAVER: You can take your guesses as to what X Edison facilities would be --

MR. MILLER: I understand. It would be, you know, controversial, but could be instructive to see --

MR. VIDAVER: Yeah, agreed.

MR. MILLER: -- to see the results. Okay. And the last comment I would like to make is, and actually this goes back to yesterday, and this is one we had a discussion on, on electric rates.

And it was a pretty good discussion going on, and a lot of, you know, controversy on being able to forecast those going forward. And I thought that this effort with the scenarios, I thought it would be extremely useful if you could roll forward the impacts of each scenario into a rate guesstimate.

I think it would be very -- in other words, take a value chain approach. See the impacts to the costs of the transmission systems; see the cost impacts to the wholesale power; or renewables, supporting the renewables mandate. All those things.

And if you could look across that spectrum I think it would be very instructive for making policy decisions, perhaps. So, that's it.

MR. VIDAVER: Thank you very much. One observation about a very small point, yet significant point. You said look at the income streams from the energy markets in assessing the viability of new combined cycles.

I mentioned that we look at the capacity factors of new combined cycles, and we want to drive them high enough when they reach a certain point that we decide it's time to start adding peaking units.

When we get combined cycles up to, you know, 80 or 85 percent or whatever, sort of equilibrium operating level we think that they would be at, we will then, of course, check the market prices and see what kind of spark-spread we're looking at.

And heaven help us if that spark-spread isn't high enough. You've run these models. You know sort of the -- in some sense it's kind of an art.

Another observation is that right now, and I don't want to speak for our engineering office, but estimates as to the cost of, the incremental cost of transmission upgrades, when you move from scenario to scenario, are not readily available to us.

Now, we may have that capability and I may not be aware of it. Again, we may come back to you and ask you for your input in that regard.

The two scenarios that -- a third comment is that we also have a difficult time, we have to make a lot of assumptions when it comes to non market sources, or non energy market sources of revenue. Most people, when looking at these problems, make some very generic assumptions about ancillary service revenue will be 5 percent of energy revenue, or something like this.

So, looking at the financial consequences as you move from a baseline into a scenario is a little bit difficult. We certainly don't question the value of doing that. In fact, that, from a social perspective, that's probably the most important thing we can be doing, looking at all the costs associated with different choices regarding reserve margins and reliability in trying to assess what kind of bang you get for your buck.

You, of course, will be the first person to acknowledge that coming up with numbers related to those different scenarios might involve a lot of rather heroic assumptions. So, assuming we do move forward as you suggest, we ask for your forbearance when we roll out the final results, and say that we made certain assumptions about ancillary service revenues, et cetera, et cetera.

So thank you very much for the suggestions. They will be taken to heart.

So, any more modeling geeks out there?

MR. SMITH: My name's Don Smith from the Office of Ratepayer Advocates, and I have two comments.

You said a few minutes ago that there's no mathematical way to determine the firm capacity for wind, and I disagree. It's the effective load carrying capability. And it's been done for the various windfarm areas in California including several studies by me when I was working for PG&E. And it's approximately 25 percent of the rating, not the much lower numbers you were giving.

My second comment is it's kind of misleading to speak in terms of reserve margin in that we really want a system reliability; want to measure probably in a loss load probability number. And you can have the same reserve margin and one system will be much more reliable than the other, or less, depending on the relative -- well, the absolute reliability of all the units, all the power plants, and the relative size, particularly at the largest plants in the system.

If you have one huge plant, say, supplying 20 percent of your peak load, and if you had a 19 percent reserve margin that would definitely not be good enough, because that one plant going down, and you have a loss of load.

So, those are my comments.

MR. VIDAVER: Regarding the second comment, we understand that the reserve margin alone doesn't tell you about the reliability of the system. The forced outage rates, unit sizes, et cetera, all impact this.

At this point we're unwilling to go

forward with the models that we have, and use the LOLP output to sort of search for the set of resource additions that yields a one-day-in-ten-year LOLP, for example. That's a very time-consuming kind of iterative process where you try and get to that number while, at the same time, you don't necessarily have great confidence in the ability of the model you're using to generate that number accurately.

We're long past ELFIN and one utility and a very simple step function for imports. These models are black boxes whose output can't be taken necessarily without several grains of salt.

One of the concerns that we have is when we look at LOLP numbers out of the models that we use, they tend to be really low. They tend to be, you get down to reserve margins below 10 percent before your LOLP starts to get to a level that calls reliability into question.

So, I don't want to go so far as to say as though there's something wrong with the model, but again, it has to be taken -- the results have to be taken with several grains of salt.

The other observation I would make on this particular topic is that there's a political element involved. And even if the model could prove to us beyond a shadow of a doubt that a 9 percent reserve margin yielded an adequate amount of reliability it would be very hard to sell.

These models also make a number of other assumptions, including the participation of generators with an absence of withholding, et cetera, et cetera.

So if a model is giving you an adequate LOLP at a 9 or 10 or 12 or 11 percent reserve margin, you sort of have to call it into question. But your point is well taken. The reserve margins, while they tell you something, they don't tell you everything.

Regarding the load carrying capability of wind, I will admit to not having read the studies you participated in. And I am amenable to doing so. However, at the time of the system peak in southern California during the past several years, Mark Minick could probably give me the exact number, but I think you have 1200 megawatts of -- you, we have 1200 megawatts of wind capacity in southern California.

And at the time of the system peak over the past several years, the amount of energy that's been generated by those units has been barely in double digits. We're talking like 20 megawatts out of 1200 megawatts of capacity have been generated on system peak.

And while there may be a methodology which validates a contribution of wind of 25 percent to a resource accounting process, let's just say you could possibly convince me of this. I don't want to say that wind doesn't have value in the system at all. The Commission has taken really strong stands on the value of renewable generation, including wind, and supports it; and will continue to do so.

But, from a planning perspective certain realities have to be taken into account, and this being one of them. Now, if there's a way to circumvent this, I'm all for it. But, again, this is a modeling exercise. This is not a policy proposal or anything like that.

MR. MINICK: Mark Minick from Southern California Edison. I'm trying to sit back there quietly and absorb what's going on, but since you are talking about wind, possibly in our service territory, we have done some studies. And I appreciate that you've done some studies in the past.

From a modeling perspective I'm comfortable with what David's doing. I would have difficulty saying that wind, at the time of the system peak, either ISO's peak or Edison's peak, can carry more than about 10 percent maximum in dependable operating capacity for the purposes of reliability. And the energy, likewise, is going up. And I appreciate that.

As far as LOLP calculations, we're trying to do them. And I accept David's explanation that it's somewhat difficult. What we did in one case, David, was the model seems to think you don't interrupt firm load until you get to zero percent reserves. So push it up three because the ISO will probably start interrupting load at 3 percent. So that'll push your 10 to 13; it helps a little.

MR. VIDAVER: Thank you. Everybody's looking at me like I'm supposed to talk. I think one of --

CHAIRMAN KEESE: I would --

MR. VIDAVER: -- supposed to talk now.

CHAIRMAN KEESE: -- just confirm, we get reports through different forums on what the generation for wind is, and we have days when it's been at 10 megawatts. So there are days when it is, the wind is not blowing in California. And generally they coincide with hot days, which are system peak days.

MR. VIDAVER: That's why they're hot, usually. No wind.

MR. SMITH: Implicit in what you just said is that when you're thinking about system reliability you're, in effect, assuming that all the risk of system failure is concentrated in one hour, or just a few you choose. You're assuming you know ahead of time exactly what the peak load is going to be in megawatts, which you don't. There's a probablistic distribution there.

And you're assuming that the dispatchable plants have absolute reliability. That's not true, either, because you get a probablistic distribution again when you look at what you can really get at any given time from your system.

So I think, because all of those three things are not correct, that you're dealing in a more probablistic situation. You have to look at a huge number of hours; see how wind is doing;

calculate system reliability with and without it. And that's how you can find the effective load carrying capability.

And I've been having this feud with SCE in some of the proceedings, and I'm sure it will continue. That's my opinion.

MR. VIDAVER: There's one point of clarification, and that is that the models that we use have a representation for thermal unit outages, meaning that there is a draw in every hour as to how much capacity is going to be sidelined due to unanticipated maintenance needs.

So that in a representative hour, peak or otherwise, about 6 percent of your system thermal capacity is not going to be available. And in some draws that number can approach 10 percent.

So I don't think we're assuming that all thermal capacity is going to be available in the peak hour or any other hour, for that matter. But I don't want to get into the middle of a feud between you and Edison, so --

(Laughter.)

MR. VIDAVER: Sorry.

PRESIDING MEMBER BOYD: Anyone else in

the audience have a comment? I think you're retired, David.

MR. VIDAVER: Thank you. Is that a polite way of saying that -- no, okay.

(Laughter.)

PRESIDING MEMBER BOYD: Time's up.

MR. VIDAVER: Cold standby. Okay, thank you.

PRESIDING MEMBER BOYD: Thank you, that was a long day for you, David.

Al, do you want to introduce the next subject at least?

MR. VIDAVER: Oh, yeah, I'd be happy to. I think she would like to know how to --

PRESIDING MEMBER BOYD: He responds to Al, too.

MR. VIDAVER: Both of us would like to know how we get this -- I'll let Al do it.

(Pause.)

MS. GRAU: All right, our technical difficulties have been solved. I'm Judy Grau with the transmission evaluation program. And before I get into my presentation I just wanted to note a few things.

First of all, I'd like to thank the

staff members who assisted in writing chapter three, which is the electricity transmission infrastructure chapter. And that's Don Kondoleon, Mark Hesters and Clair Laufenberg.

The other thing I'd like to note is that if you picked up a copy of the infrastructure report you should have an errata page inserted in there. It goes with appendix B, table B-7. And so if you do not have that insert, I think we have extra copies in the back. I can get you one after my presentation.

And the other thing is Gary DeShazo of the California ISO will also be making a formal presentation, PowerPoint presentation, right after mine on the ISO's comprehensive transmission planning process.

And so what I'd like to do, in the interest of time, is to do my presentation; have Gary do his; and then have the panel approach. Because some of your questions may be best answered by one of the utilities or the ISO. And so we have several folks who have volunteered to be on a panel, and it might be easiest to save all your questions when the right person is already up at a microphone and can answer.

So, if that's okay, unless you're absolutely dying, we'd like to try and hold the questions.

Okay, the topics I'm going to cover pretty much follow the outline of the chapter three. So if you've read chapter three, this should all look familiar to you.

First we're going to talk about the major transmission projects modeled, and you'll see some references to what Dave Vidaver talked about this morning in terms of the transmission topology and what assumptions we're making.

And then talk about local reliability projects, some economic projects, transmission to support renewables, and then finally the out-of-state projects.

And so there are seven projects that I'll be talking about here that fit in with our transmission topology. So let me turn to that slide to point out where these projects are.

The first one from north of Path 15 to San Francisco would be the Jefferson-Martin project upgrade which we'll be talking about; I'll talk about it in the next slides. I just want to point them out, where they are on this figure, because they're not marked.

From Zonal Path 26 to north of Path 15 is the Path 15 upgrade. From SCE to Zonal Path 26, this is Midway-Vincent, a short-term upgrade. And I'll talk about short term versus long term.

From SCE to SDG&E, this is the path that would include the Valley-Rainbow upgrade assumption. From SDG&E to Miguel is the Miguel-Mission upgrade. And from SCE to IID is part of the Path 46 west-of-river upgrade we'll be talking about.

And the final one s a Path 45 upgrade. Path 45, at least on this topology is both of these paths, Tijuana-Miguel and LaRosita to Imperial Valley.

And I'll be talking about these in the order in which we are modeling them to become available. So the first one is the Path 45 upgrade. And this, as I noted, -- oh, sorry, don't have the picture up anymore -- but this is from LaRosita to Imperial Valley. That reconductoring of the 230 kV line was already completed. It was completed in November 2001. And increases the transfer capability.

However, the current status is that the

WECC has not yet approved from south to north the summer rating increase to 800 megawatts. So staff is going to model it 800 megawatts bidirectional because we expect that WECC approval very soon.

The next upgrade is a short-term upgrade from Midway to Vincent. And this is primarily an operating procedure change. I think it involves some remedial action scheme work and such. This is considered an economic project, not a reliability project, as some of the others are.

It is under construction at the moment, and if you look in our tracking sheets at the back, Southern California Edison has a predicted online date of June of 2003. But staff has heard in another venue that PG&E has a slightly later date of September 2003. So if you have any questions maybe when we get the utility representatives up for the panel, they can talk about why there's a discrepancy.

And from a modeling perspective then, this increases the transfer capability bidirectional from 3000 to 3400 megawatts. And we're assuming the later date, so we're using October 2003.

The next upgrade is the Path 15, Los

Banos to Gates. This is also an economic project. The project is being sponsored by Western Area Power Administration, Trans-Elect and PG&E. And we do have Morteza Sabet of WAPA here, and he can talk more about the project also again when we open it up to the questions for the panel.

And this increases -- we have the modeling assumption that this increases the ratings as shown, and we're using January 2005 as the effective date for that.

Next project is Miguel-Million in the San Diego area. And this, again, is another economic project. Current status is, for those of you who have been following the proceeding, no CPCN is needed for the Imperial Valley upgrades, but there will be CPCN needed for the Mission-Miguel line. But the PUC has agreed to expedite that and take the record that's already been developed.

So our modeling assumption is that that will occur and increase the transfer capability into the downtown San Diego area as of January 2005.

Next upgrade is the Jefferson to Martin in PG&E's territory. This is a new 230 kV line.

It needs a CPCN. And that was filed at the PUC on September 30th. And there's a prehearing conference January 10th. We are assuming that that will become available as of January 2006.

All of these projects, by the way, can be found in the appendices. Appendix table B-1 through B-7 are the seven planning areas for PG&E. Table B-8 is for San Diego. And table B-9 is for Southern California Edison. So these are all in there.

The next project involves Path 46, west of the river, and I think Dave talked about this this morning, that this one is not an actual project being proposed or sponsored by anyone at the moment. But it's just the conceptual idea that with all of the -- to meet the renewable portfolio standard we may need -- that may be met, I should say, by geothermal development in the Salton Sea area.

And to get all that generation out there's going to probably have to be some sort of transmission upgrade. And so for purposes of our baseline assumptions, we're assuming an increase from the IID to SCE interconnection of 1000 megawatts in January 2009.

And then finally, or maybe not so finally, yeah, this is the last one of the major projects, is the Rainbow-Valley project. This would be a new 500 kV line from the existing Southern California Edison Valley substation to a new San Diego Gas and Electric Rainbow substation and then some other ancillary lines are also part of that upgrade.

This is considered by San Diego to be a reliability project. Many of you know that they filed for a CPCN and it was denied by the PUC, I think in December 2002 as being not needed for reliability until at least 2008. And the current status is that SDG&E has filed for a rehearing. And as far as we know, no action has been taken yet.

For purposes of our modeling we are assuming an inservice date of January 2009. And, again, as Dave has said, and as some of you know if you've followed the case, this all hinges -- it hinges quite a bit, the argument, on whether Otay Mesa comes online in the local area in 2005 or not. And because San Diego is a local reliability area, the baseline assumption is that something will be built to meet need by December 2005, whether it's Otay or Palomar or something else.

And so we obviously will be looking at alternative scenarios that don't include Otay Mesa or other local additions, but just confirming that for baseline purposes we're assuming it'll be deferred until 2009.

Okay, moving on then to the local reliability projects. These are the ones that are needed to conform within Cal-ISO's planning standards timeframe, within five years. I put for the 2002 process, because as Gary DeShazo will be talking about, the ISO has come to the conclusion that a minimum five-year time planning horizon may not be enough to get some of these projects underway, as we saw kind of in response to the Valley-Rainbow denial. So, we'll be talking more about that.

But for now, what I have included and analyzed in our chapter is based on the 2002 process in which the utilities responded with plans that looked out just five years, within a look beyond at other major projects, but for the most part within five years.

These plans are updated annually and submitted to the ISO, so it's an annual update of the five-year plan, or at least it has been. Current status is that the 2002 assessments have been completed and we're just getting underway with the 2003 assessment process.

And so just briefly, I have six categories of utilities of projects that I'll be talking about. I'm going to go through this pretty fast because if you have read the chapter it's all in there. And I know we have a lot to talk about this afternoon.

Just wanted to briefly state where I got the information that's in all those appendix tables. And I used each of the utilities' final transmission expansion plan reports. And the monthly filings that the utilities make to the PUC as part of their AB-970 requirement. And then also the California ISO's control grid study report which is available on their website.

And as I noted earlier, there's seven planning areas in PG&E, and this is the breakdown. The names of the planning areas, as well as how many projects, are in the tables in the appendices, that we are reporting on.

Same thing for San Diego. Sources of information was their annual grid expansion plan, plus their monthly filings. And the ISO report, again. And they have 23 projects that are reported on.

Southern California Edison, same thing. I have a slide mentioning the Tehachapi project, specifically. I had foresight that you'd be asking about that, so I put this in here. Anyway, they have completed the phase two Tehachapi transmission conceptual study. A CPCN would be required, and it's listed in the tracking sheet as being in the planning stages for the projected online of December 2006.

In the Imperial Irrigation District we are aware of two expansion projects, two options I should say. In our staff draft report we mention three options, but that option, from what I understand from our staff working on the siting case for Blythe II, that option is no longer being considered.

Blythe II is in our permitting process right now. And there are some project changes they've been making which are causing some delays in schedule. But, again, as Dave said, you know, we're not assigning any yea or nay to whether that project will receive a permit or not. We're just noting that there have been some delays.

And Blythe I, which Dave Vidaver also had in his slides, is coming online. The expected date for that is April 15th, so that will be soon. And it's my understanding that the existing transmission system in that area is sufficient to handle the generation from Blythe I, the 520 megawatts from that. And this expansion project noted here would be needed if, and only if, Blythe II is constructed.

And then in the western area they have an environmental impact statement done for a proposed project that includes some reconductoring and a new double circuit and various realignments, as noted here. And this is a reliability project. This area has been studied quite a bit through the Sacramento area transmission -- what's the PG? Planning group.

They've been looking at that. So my understanding is that the comment period has ended and the distribution of the final EIS is scheduled for May 2003. However, they're still looking for funding sources, but Morteza maybe could tell you more about that. And right now we don't have a projected inservice date, but again, maybe Morteza could shed some light on that, too.

The City of Santa Clara Silicon Valley Power, they had, I think, it's a four-mile transmission line to connect from their northern receiving station to PG&E's new Los Esteros substation. This is included in PG&E's table for PG&E. You'll see that in there.

The Los Esteros substation is supposed to be operational in May of this year. And then the line from the northern receiving station to that new substation, the Santa Clara line, will be, should be operational by the end of 2004, at least according to their website.

Additional economic projects. I've already mentioned some of them. Path 26, the short-term solution. Path 15, and the Miguel-Mission and Imperial Valley substation. And those are all major projects that we are modeling in our transmission market SIM program.

There's another Path 26 long-term solution which would involve some reconductoring of 500 kV lines. And this would bring the capacity from -- the short-term solution brings it from 3000 to 3400 transfer capability. This would bring the transfer capability up to 4000 megawatts, bidirectional.

And the current status of this is that it's in the planning stage, and I don't believe there's an online date, but if someone from the ISO or the utility would like to comment further when we get to the panel part, please do so.

Transmission projects to support renewables. I think most of you are probably familiar with the renewable portfolio standard and the statutes and who's doing what for that. As you know the Energy Commission has to provide the draft renewable forecast -- renewable generation development to the PUC by July 1st. And then the CPUC is charged with actually creating the transmission plan.

And there was just a ruling from ALJ Gottstein this morning, so for those of you on that proceeding, watch for that when you get your email. And she lays out some timelines and dates for who's going to do what by when. So you can read about that.

And that, just noting again we're assuming 1000 megawatt increase from IID to SCE, and that's to accommodate the renewables in the Salton Sea area. And, in fact, Coral Power, LLC, has proposed a 500 kV line from the Imperial Valley substation to the Southern California Edison Dever substation. And the January 29th ruling by ALJ Gottstein has ordered the utilities to investigate the feasibility of that.

The out-of-state projects. We are aware of the Trans-Elect and Dine Power Authority developing the Navajo Transmission project. As I've heard from Don Kondoleon, he says there is no impact on California of that upgrade unless there are other west-of-the-river upgrades made. So that doesn't -- you won't see that in our model because it doesn't affect California.

Another study group, though, in the southwest, Southwest Transmission Expansion Plan, the STEP group, they are looking at facilities to increase the transmission and transfer capability in Arizona, Nevada, Mexico and southern California. So there may be some longer term projects coming out of that effort.

And then just turning to the questions. This is the short version of the questions David had at the end of his slides. But before we get into answering those questions, I'd like to turn it over to the ISO, Gary DeShazo.

And then we'll open it up to the panelists. And as far as I know, so far, Morteza Sabet of Western, and then Gary, as well as maybe Robert Sparks from the ISO, and then Chifong Thomas, I understand, from PG&E might like to be on the panel. And then anybody from Edison or San Diego, of course, is welcome to join us, also, or any other utility.

So, let's turn it over to Gary.

MR. DeSHAZO: Thanks, Judy. My wife has all kinds of names for me, too, so I'm used to that.

I'd like to just introduce myself. I am Gary DeShazo; I'm Regional Transmission -- or Regional Planning Manager of California ISO. And I just would like to extend my appreciation to those of you involved in setting up this process for allowing me to take a few minutes of your time to talk about the transmission planning process that the ISO has in place.

I have been in the utility business for probably a little over 24 years now. The first 23 years of my career -- all of that has been in transmission planning, by the way -- and the first 23 years of my career was with the Salt River project, which is about a 5400 megawatt utility; and it's located in the Phoenix metropolitan area in Arizona.

So, David, I'm very familiar with places like Santan and Mesquite and all of the stuff that's happening at Palo Verde and so on and so forth.

When I made a decision to leave SRP and come to work for the ISO I got two comments from my peers and friends there. And one was, you know, what are you thinking, you're just going into the frying pan, and those folks don't even, they don't know what they're doing.

And the other is that, you know, do you even understand what change is all about.

Well, you know, I've been at the ISO now for a little over 15 months and I guarantee you that I understand what change is all about, because that's what that job is about.

With regard to whether or not people here understand what they're doing, I guess I sort of look at that as someone sitting in an armchair watching a football game and second-guessing what a quarterback does.

And I will tell you that this is

probably the best move that I ever made, because the people that I've had the opportunity to work with, and I think you've seen some of that this morning, are very dedicated individuals. And we all recognize that we've got some difficulties and problems, but we're all focused on trying to figure out how to make it better and how to look out for the long term needs for the state in terms of our energy needs and transmission needs.

It's been a very interesting process over the last 15 months, learning about how this stuff works. But I've noticed some things that have not seemed, at least, to be coming across very well. And one of those is with regard to the planning process that the ISO uses.

And so I've struggled with whether or not to fit into the effort that you have going on here, but I think after listening to the speakers this morning and this afternoon, that, in fact, I think we do very much fit into this.

And so what I would like to do is just, I realize you're kind of short on time, and so I may just sort of skip through some of these things. I know there's some animation in some of these slides, and we'll see where that takes us.

But, I would like to just spend a few minutes and just maybe go over the planning process that we have. And then talk about where we are heading, where the ISO is heading in 2003; take us beyond just the standard or traditional planning process that we have been using.

I think the first thing that we want to maybe take a look at is what's shown up here are the three major what we call the PTOs, or the participating transmission owners. These are Southern California Edison, San Diego Gas and Electric and Pacific Gas and Electric.

And each year the ISO enters into an expansion planning process with these PTOs to develop a ten-year expansion plan for their system. We work with them individually. They go through a process, a very stringent stakeholder process, where they look at the transmission requirements and facilities that are needed in order for them to meet all of the reliability obligations that they have.

As part of that process the ISO does what we call a control grid study. And the control grid study is an opportunity to feed the information from the expansion plans into a common database, so to speak, where we take a look at the 500 kV system, or what I called the backbone system in California.

And the concept here is that we're trying to find a way that we take these individual expansion plans; and then we perform this work; feed that into the control grid study; and make sure that at least at the -- level, ties together.

Now, in addition to that there's other things that are shown up here in yellow with regard to processes that the ISO also goes through. Most of you, obviously you probably recognize the reliability must-run generation studies that we do on an annual basis.

We also have now become responsible for new generation, new generator interconnection requests. And we also will do special focus studies from time to time as the needs arise.

Well, if we look at what the control grid study is, and if we just think about the fact that it's the home for the overall process, then the key is how does all this stuff fit together. And what the control grid study does, in essence, is to try to bring all of the expansion plans together in concept so that you have a tie between what the PTOs are doing, the overall assessment and independent assessment by the ISO to look at how that impacts the transmission needs, and to make sure that they match up. In other words, we shouldn't be finding anything in the control grid study that the expansion plans haven't already found. And vice versa.

And so it's sort of a checks-and-balances thing in terms of the process. The control grid study is also a stakeholder process, just like the expansion planning process is. And, as always, we still have these yellow circles out there that are other things that we do.

But the key is that while they don't, you know, it sort of looks like they sit out there by themselves, they don't really do that.

What I'm trying to illustrate here is that there's a stakeholder process, and I sort of call this green area the world of stakeholders, that's the glue that ties all of this stuff together.

The concept is that the stakeholders are participating in all these processes. And while we're involved in trying to get the work done and develop the needs and assess the transmission facilities, the stakeholders are also there to bring forward what their concerns and ideas are. And they may see issues in RMR studies that may have some implication with regard to how an expansion plan is done, say either in PG&E or Edison's area, or elsewhere.

And so the green area is a way that allows the stakeholders to sort of traverse the boundaries between all these processes that we have.

In essence, making this work, we have several pieces of this puzzle in terms of how this gets facilitated. The ISO, of course, takes the leadership role in doing this. We are establishing the reliability and economic need of transmission facilities in the state.

We take a longer term overall view of the transmission and reliability needs. And most importantly of all, our intent is to collaboratively work with the PTOs and the other stakeholders, as well as the state.

At the same time you have the PTOs, they have their process where they're the ones that are actually performing the technical studies to develop the expansion plans. They focus on their internal systems. And I think that that is where many have erred in thinking that we only do five-year planning studies. Okay, because they focus really in depth on that five years so they get a good idea of what they need so they can go do their budgeting process.

But if you look into the expansion plans, and certainly within PG&E's expansion plan, which I'm mostly involved with, you'll see it goes beyond that. Okay. And the intent has always been to go at least out to ten years. And I think that the utilities, prior to the ISO's existence, were doing those kinds of things. It really did not stop. But for some reason the process just kind of got focused down to this five-year period.

So, I'm trying to stop that mode of thinking; and get people to thinking again that it's something that's longer than that.

You know, they're also involved jointly in performing in the long-term planning processes that we go through. And, of course, they also have the collaborative process that they go through.

But, here, again, this is the most important part. It involves the stakeholders and the state. I've sort of separated the state out. I struggle with whether, and I don't want to call the state entities a stakeholder; and I guess in essence, in an overall view, that's true.

But, it's probably not appropriate simply because they have -- different entities have other obligations and things that they must do in order to get their jobs done. And so they're bringing those concepts to the table. So I've kind of set them out apart from the stakeholders, even though they are part of the stakeholder group.

But the point is that what these folks do is they provide the glue that really holds this stuff together. They participate in the processes, at least we're hoping that they're participating in these processes. They're providing the guidance and recommendations on process objectives. Okay, we know what we want to do with the expansion plan, but the expectation is that these folks will bring forward their concerns or their needs, as they seem them in terms of how they view the world, they'll bring them into this process so that the ISO and the PTOs can try to address them.

They assure the continuity of the information across all the stakeholder forums. To me, I just think that's a given. And obviously they also have a collaborative process that we would like -- or that we follow with both the ISO and the PTOs.

So, where does that leave us? There are a lot of challenges. I have listed up here, you know, a number of challenges that I just threw on a slide. You can probably think of many many others.

But the question is, is it enough. Is what we're doing enough? The ISO, at least over the last year to year and a half, has come to the conclusion that no, it's not enough. That we need to be doing something more than just our traditional expansion planning process, our RMR studies and our occasional focus planning studies and so on and so forth. There's other things that need to be done.

So what we have sort of come up with as the concept -- it's not really a concept, we all understand this, but regional long-term transmission -- it's the piece that says, okay, we go through our five- and our ten-year efforts.

But the question is what do we do beyond that, okay.

I think that the Valley-Rainbow process and how that ended up will probably forever stick in my mind with regard to some of the things that came out of that.

But one of the questions that was asked in that process was, well, so how does this fit. We understand that you're talking about need, okay. And we understand that you're trying to define this project based upon that. But how does it really fit? Is it the right thing to do?

Now, I don't know about you folks, but I believe that that's a very good question. And I think it's a question that we sort of have been missing. And we've come to a point now, and for whatever the reasons were that the decisions were made, just the essence of the questions alone, I think, says we need to do something different.

And so the regional long-term transmission study, at least as we see it, is there to accomplish a number of things. And you may see other things that it would accomplish, but in concept it's there to define a master plan for some of these, what I say a short-term project fades, but it's really for things like the Midway-Vincent line, or, you know, new 500 transmission facilities that may be proposed. How do these fit overall into the state, into the long return needs of the state.

It involves the stakeholder process which was probably even much more important than any of the other things that are done, because the key here is that you have people out there that want to do things. They want to build transmission; they want to build generation, okay; or maybe a combination of both. And they have something to say about that.

The problem is where do they get their input; and how can it be managed in a manner that allows it for that to be a meaningful process.

The state resource plan. Bottomline is that there isn't much that the ISO can do without that kind of involvement, okay. We have a lot of expertise within that company. But I, you know, I can't truly say that we have the right expertise to do these kinds of things.

And so I think that one of the things that the ISO has come to realize is that while we have a lot of expertise in operating the system and doing planning studies and establishing need, there still are issues related to load forecasting; there's issues related to assumptions about generation and so on and so forth. That there are other entities within the state and other areas that are very well geared to providing that kind of information.

And so the process needs to provide the opportunity to allow that input to come in so that we can take that into account.

The opportunities for addressing reliability, economic needs and minimizing environmental impacts and costs, these are just standard things. We always want to do that. But the reason for bringing that up here in this part is that it really sort of brings another perspective into what a transmission planning process is.

It isn't just about performing technical analyses, okay. It's really, it's very complex. And you just don't go out and run a bunch of power flows and then come up with a bunch of answers and say here it is, this is what you're going to go do, or this is what you should do, because it's a lot more complicated than that.

Is five years enough? I don't think anybody in this room believes that five years is enough. If you do, then, you know, we probably ought to have a conversation about that. Because in some cases, it is; in some cases, it isn't. And what I've heard from questions and comments that were asked and made earlier this morning, that's precisely the concern that people have. Is how can we be assured that the things are going to get done. Okay.

If you want, you know, if someone's asking, well, maybe we should look at no transmission growth and see how the generation is going to fill in those gaps, where is that really coming from. It's that concern about can it all fit together. And that, I think, is what we really need to try to do as groups, and the diverse groups that we have, is try to find a way to fit this stuff together so we can do the right thing for the state.

As a plan, it's got to handle a lot of different things. It's got to handle a lot of different variables. It's got to be something that's beyond ten years, because we've got to drive a process that forces people to ask questions that are really non technical. We have to force a process where people are starting to ask themselves, what is the right thing to do in the future; how do these things fit together.

That you provide the opportunity for others that are not either the ISO or state organizations, but others that have interest in wanting to do something, to provide in put, so that they want to build a transmission. If they want to build generation, and maybe they don't have the opportunity to build additional infrastructure to get the gasline there, what's the problem with trying to work with a group of individuals that say I want to build a transmission line from point A to point B. And if I have to try to route it over here to where this person is, so it picks him up, what's wrong with that. Why is that any less of an alternative, okay, than any other thing that we look at.

Where do we provide the opportunity in the process for those kinds of things to occur. We don't. We need to fix that.

We think that -- I've kind of harped on the technical part of it, but it's really a multifaceted thing. It isn't just about running technical studies; it isn't just about generation or transmission. It's about gas infrastructure; it's about water; it's about environment; it's about NIMBYism; it's about a lot of different things.

And while I cannot tell you exactly how you need to put all that stuff together, I can tell you that we need to be looking for a way to try to make that work. So, it's a multifaceted process that's going to require a number of different things.

Now, we spent a lot of time talking about the state and its needs and where we've been and where we want to go and how we want to get there, and who's going to be responsible for that. But the bottomline is that we're not isolated. We can't be isolated.

And so what you have is, mentioned a couple of times, the process that's occurring in the southwest called STEP. It was initiated by an old boss of mine who initiated a process in central Arizona called the CAT study, or the Central Arizona Transmission study.

The concept that they came up was that, look, we know we've got all, we've got 10,000 megawatts of generation that's being proposed to be sited at Palo Verde, okay. I don't mean like 30, 40 miles away; at Palo Verde. These guys are all -- you can see the plants from one spot, okay, 10,000 megawatts. That's how that got started.

And there's also a need, you got Tucson sitting down here, and there's also a need, in terms of Phoenix growing very quickly, how do you -- where's the next transmission line to be built. And we already knew because of the political environment that Arizona was facing, with all the generation that was being proposed, that simply going in and SRP saying we need to build a 500 kV line to the southeast part of our service territory wasn't going to cut it.

What we had to do was to get all the utilities in Arizona involved and say, okay, this is what we want to do. What do you guys want to do. And then can we structure something here that maybe fits everybody's needs.

And so out of that was born this CATS process, which was very much not anything about technical studies, but a lot about getting people together talking about what their needs were. And then drawing a bunch of lines on a piece of paper and saying, this is where I want to go, this is what I want to do, this is how I'd like to accomplish this. And then trying to find some commonality out of all that.

The process worked very well. And so this individual has brought this to southern California and said we would like, because we got this generation sitting down there, we'd like to find a way to get rid of it so maybe we can export to California and make some money. So maybe we can find a way to develop some transmission alternatives between the southwest and southern California.

And so that STEP process was born out of that. And if you think about it in terms of what we want to try to accomplish in terms of long-term planning, and regional planning, long term planning within the state, that kind of fits very well into that.

But at the same time we've heard some comments today talking about, well, it's a bad hydro year in the northwest; things aren't being done up there. And it has a great impact on what we do in California. And whether or not we're going to be able to meet our load forecast and so on and so forth.

And that just says to me that you can't stop with something going between the southwest and southern California. That we need to also move further north and look and try to develop some kind of process with the folks in the northwest, okay.

Now, I've dealt with pretty much all the utilities in the western United States. And, you know, the southwest, in dealing with folks like Edison and San Diego, they're pretty easy to deal with. When you go to the northwest, these folks look at things a little bit differently. And so, that's not going to be an easy process. But I think it's something that we need to do and the ISO believes needs to be done.

So, as part of our overall process with regard to developing this regional planning effort, will be also to try to initiate sort of a STEP type process with the northwest.

There's a number of things that we want to do, at least that I wanted to do. I've kind of covered all of these. I have a very great desire to refocus our expansion planning concept to a ten-year concept, which is what it was intended to be from the very beginning. And I think working with the PTOs we can get that fixed, because that's really what they're doing. And so we can make that happen.

That we need to improve our integration of all of our ISO planning roles that we have; all those circles that I showed that seemed to be kind of independent processes. They all have something to offer in the overall needs of planning for the state. And so we need to do a better job of integrating those things together.

My belief is the expansion plan is where that ought to be done. The bottomline is I think, that if you look at the transmission planning communities in these PTOs and think about what is the single most important thing that they do each year. And that is develop their expansion plan.

And why is that important? Because that is what they are giving to the public and telling you how they are going to meet the reliability obligations for the next five to ten years. That has got to be important to people. It's got to. So the expansion plans needs to be that method and that mode to be able to accommodate that kind of information. And I think we can work to do that.

Obviously we want to develop the long-term regional plan as part of that.

Your process here, I think that we have a lot to offer you in this process in helping you refine your long-term information needs. You have a lot of questions about that. We have processes and expertise in place. And we can help you, and we stand ready to do that.

Terry wants us to interact with the folks. We want to be supportive where we can. We think this is a great process and we think we have a lot to offer you. And we would like to do that.

We think that you have also a lot to offer us in terms of our process. There's a lot of opportunities to provide the information to us with regard to how we build these cases.

Like I said, we have expertise in doing, in talking about resources and talking about load, but I think, and I believe that the ISO thinks that there is better expertise out there.

And so what we'd like to do is to talk about collaborative efforts here, as I think what the ISO is really interested in doing is collaboratively working with people to develop this information so that we can get it in the process as it goes through. We can put that in our planning studies and we can find what the transmission facility needs are, and then we can move on. So I think there's a way to do that. We just need to work out the details for that.

I'd also heard a couple of comments this morning about I think someone had mentioned something about a rational development of transmission system. I think maybe you might have mentioned that. And I could not agree with you more. I struggle with is that really happening. And I don't think it's necessarily anybody's fault. I think of all everybody has gone through over this past three or four years, we may have just lost a bit of focus.

And so it seems to me that people are getting back on track and are trying to get that focus back so that we can get the right thing done.

The other comment that was mentioned was the lack of the standardized approach to developing load forecasts. And I can't agree with that more, either. Because that is one of the biggest issues that we have. We can put any kind of loads into a power flow and we can determine anything that you want. The problem is what credibility does it have. And I think we need to come up and develop some kind of a process that lends that credibility to it so as we step through all these processes that the state's required to go through, that at least we can have some credibility behind some of these things.

With that, that's all I have. I would just like to again tell you how much I appreciate the opportunity to speak with you. The people that I've heard speak this morning and this afternoon, it's pretty evident that you're very much -- put a lot of thought into this and that you're on the right track. We look forward to working with everyone that's involved in this as the process goes forward.

PRESIDING MEMBER BOYD: Thank you, Gary. Does anyone in the audience have questions? Let's see, you asked me to hold those, didn't you?

MS. GRAU: Thank you. Yes, at this point I'd like to invite Gary -- wait, don't sit down yet. We're going to have the opportunity for people to ask questions of anybody on the panel. So Don Kondoleon and Mark Hesters from the CEC Staff, as well as myself, and then Gary and

Morteza Sabet and Chifong -- I don't -- if you'd like to join us. And anybody else from the utilities. We'll get some more seats up there. And then questions from the audience, we'll be happy, among all of us, the best person hopefully will jump forward and answer the question.

(Pause.)

PRESIDING MEMBER BOYD: Kind of emptied the audience there.

UNIDENTIFIED SPEAKER: Is there anyone left to ask questions?

(Laughter.)

MR. SKOWRONSKI: What about the RTO concept? I mean how is this going to be impacted? We seem to be circumventing or skipping over something that looks like it's coming down the track fairly fast. Just a general question that I have is how RTO impact the ISO and what changes can we expect?

MR. DeSHAZO: Well, you're probably stepping back just a tad bit before my time. I am aware that the ISO has filed with FERC to become an RTO, and it seems like so many other things that they tend to sit on, that's one of them that they are sitting on for some reason.

I would not even pretend to try to figure out, you know, the political processes and issues that are occurring, you know, between the ISO and the state and FERC. The SSGWI process -- is meant to try to address the seams issues that would be associated between the three RTOs. And FERC seems to be providing that group with a lot of focus and a lot of credibility in terms of their efforts.

You know, just for the sake of knowing, I mean I've asked similar questions inside and I've not been able to find anyone that can give me any clear answer about where we think this is going to end up. I think that the ISO would clearly prefer to be an RTO. Otherwise we wouldn't have made that filing. That the SSGWI process will hopefully work through whatever seams issues that there are.

The ISO, you know, it's an operating entity; it has a lot of expertise and background. I think it's prepared to make that move. But maybe it's a political issue or other issues right now that it's not ready to occur.

MR. SKOWRONSKI: As a prospective large central power generator, what issues should I be looked for or concerned, if any, as the ISO transforms itself into an RTO?

MR. DeSHAZO: Well, I'm not sure that I would be the best one to answer that. My personal opinion is I don't see that there should be any. Other than a refocus of who has, you know, overall responsibility, I don't see that the ISO performing in terms of planning and how it interacts with individuals such as generators or transmission providers or others would really change.

There may be some concepts within the overall RTO process that would eventually need to be put together and ironed out, which we don't really know yet. But how I would work with you as a planner in finding ways to integrate you into the system, I don't see that that would change.

MR. SKOWRONSKI: Thank you.

PRESIDING MEMBER BOYD: Do you have questions for each other?

(Laughter.)

MS. GRAU: Okay, thank you very much. We'll move on now to Mark DiGiovanna, natural gas --

PRESIDING MEMBER BOYD: Here comes a

question.

MS. GRAU: Oh, I'm sorry, okay.

UNIDENTIFIED SPEAKER: Is this the appropriate time to ask for any comments about transmission or is that --

MS. GRAU: Now is appropriate. This is transmission. After that we're moving on to natural gas.

DR. ARTHUR: Dave Arthur, City of Redding. And also a member of the contracts group for TANC, the Transmission Authority of Northern California.

One of the driving forces for those of us that are called munis, whether or not that's an accurate description, is to minimize the cost while maintaining the reliability for all of our retail customers. So the retail customer is our driving consideration.

You earlier heard discussion about Path 15. TANC made a very concerted effort to take the lead in that effort. The best estimates are that would have saved the people of California about $30- to $50 million per year had that particular initiative been successful, instead of having to turn to the merchant transmission solution, which as a result of certain FERC policies will result in very high costs.

And the reason we weren't able to go forward is because we couldn't get the time of day from the involved PTO or the California ISO for any type of support.

So, earlier I had mentioned the term friction. There is nowhere in the State of California where the principle of friction is greater than when it comes to the issue of transmission.

You can expand the transmission they have proposed there, but what you can't get is assured delivery. And so the question becomes if you have responsibility to your customers, how do you make forward market purchases that require transmission when you're prohibited, outside of ownership, you're prohibited from having assured delivery?

So, as you think through your basecase and you look at policies that would be useful to recommend to the Governor, I would hope that the issue of assured delivery, which for those of us that see our existence as serving retail customers, we would hope that assured delivery is high on your list of things that need to be addressed.

Because in the environment that's being proposed for the State of California today under market design 2002, assured delivery is not an option.

Thank you.

PRESIDING MEMBER BOYD: Panel response? Comment? Anyone have the courage to address this?

MR. SABET: I do. This is Morteza Sabet of Western Area Power. I do subscribe to Dave's notion. I think we have to separate the whole concept of efficient transmission exemption. I think it is misunderstood because we mix the expansion with a certainty.

There are two dimensions to expansion. I think Dave's point is well taken. You have to have assured certainty in order to basically incent people to invest.

In terms of efficiency, if this line of work was a perishable good I think we know how to deal with that. But the issue for expansion, I think the reason we have the situation that we have today stems from basically lack of or absence of public policy and public good direction in transmission expansion.

We kind of, in a sense, put it on the back burner. We are not looking at it in an expansive or all-inclusive fashion when we look at generation and transmission planning.

Having been involved in the project that was listed as the Sacramento area, I fully appreciate the missing part which is what is good for the whole good of the organization or, in this case, the state. And I think, you know, the initiative that the Commission is taking here is the right place to address that.

So I do suggest we need to have both, an efficient expansion mechanism, as well as assured certainty with price certainty.

MS. THOMAS: I'm Chifong Thomas with PG&E. One of the uncertainties that concerns transmission planning is the fact that you -- assumptions changed over time. And it is, for example, your planning a transmission line; a slight change in low projection could shift the need for the line over, could be as much as ten years.

So it's going to be very difficult to go in and go to the Commission and say, well, here we are; we need a CPCN for a line on a certain date, just like you cannot go out and say that hey, look, by year 2018 the load in California is exactly 65,345 megawatts at 3:00 in the afternoon in August.

So that is (inaudible) to that is the fact that just because something is in a plan, assumptions change, especially now with the new world we're living in with generation that was uncertainty, where the siting of generation, the load growth, that makes it very difficult and a lot of time it's just bear with us, because when we put down a line and say a certain date, it's not necessarily that it would happen.

But it's not because we're malicious or try to do something bad to you; it's just the fact that we don't -- the assumption change, and we have to change the assumption to match -- I mean the results so that the ratepayers wouldn't be stuck with paying for something that they don't need.

MR. SABET: I would like to follow a thought Chifong triggered in my mind. When you look at the old utilities when all the services were fully bundled, it was a lot easier to assume certain scenario and follow through.

It has basically become an extremely difficult to basically run your layout plan, whether it's a generation supply adequacy or transmission adequacy. Very difficult to base your assumptions, especially with the unbundling of services and the way the information flows.

To give you an example, in Western, in our area we were basically faced with about 3000, 3500 megawatts of merchant generation that came in basically for interconnection to our system. And how you basically lay out your basecase in order to study the local, as well as regional, impacts is profoundly different from one set of assumption to the other set of assumptions.

So, we basically, we get a group together and everyone basically provide their input based on their self interest, as well as global interest. And usually come up with the right approach to deal with the issues.

But the fact of the matter is the absence of transmission hasn't basically been addressed in many forums at all.

In Sacramento we broadcast the deficiency about ten years now. And we had generators coming to us, but the transmission, which is the local area transmission reinforcement, as well as some regional reinforcement, nobody wants to own. Because generators come into the basically rescue to avoid building the transmission. But yet there are times that you need both transmission and generation, both, whether it's local or regional.

And those are the issues that I think should come out of your effort.

MS. GRIFFIN: I'm Karen Griffin from the staff. I have two questions and they're both for WAPA and for PG&E.

The first one is what is the status of the Path 15 upgrade in which you're both involved? And what bumps in the road are there between now and the projected online date that's included in staff's report?

And the second one is there's a press report out that WAPA's considering becoming its own control area when its agreement with PG&E ends. And will that have an effect on the kinds of transmission upgrades that either WAPA or PG&E might plan to make?

MR. SABET: On Path 15, based on what I

know currently, I don't know of any bump on the road, so to speak. The current plan is, you know, consistent with what you have on your slides. The end of 1994 is our target energization date based on what I've heard from both PG&E, as well as our people in the field.

Our people are seriously out there, you know, looking at the field investigation and design. And we are moving right on target by the end of 1994. I don't know personally of any impediment at this time.

I hear people talking about financing issues, but I'm not really prepared to talk about it.

In terms of our control area formation, basically I can tell you this. The reason for that initiative is we have several transmission contracts that are expiring by 2004. Some of those contracts are to the northwest, some are with PG&E. We have about a majority of our customers in numbers are served off of the ISO grid in PG&E distribution system. And there's going to be a tremendous amount of rate shock or change in terms of when the contracts are going to expire.

That is basically our aim to make sure that there is not a hell of a lot of change in terms of financial impact on those entities, mainly end users, you know, irrigation pumps, end use energies that they're basically on their mind their very survival.

As a measure basically to, in case if these contracts don't renegotiate, they're not renegotiated, more or less when the status go, you know, price we understand the world around us is changing. There has to be some compromise.

Control area was conceived as an option to insulate our customers against those charges that basically are many manyfold, based on the estimates that we have heard.

So that's the initiative; we are not hundred percent on that track yet. We are looking at our options, both control areas, as well as other options to minimize the cost, and cost shifted to the customers.

MS. THOMAS: In terms of technical cooperation and studies in transmission planning, we'll continue to cooperate with Western as we always have been doing, and with the ISO and all the other entities.

MR. SPARKS: I'm Robert Sparks, the California ISO. I wanted to address Dave's question. I don't see him in the audience anymore, but he had asked a question about assured delivery. I'm not exactly sure what the definition of that is, but I just wanted to point out that one of the primary objectives of the California ISO is to provide open access to the transmission grid. And also point out that any participant can schedule on the ISO control grid.

And to the extent that there is congestion preventing delivery, that's the whole reason we have a transmission planning group at the ISO, and that we have this collaborative process to expand the grid, so that to the point that it's economically the right thing to do to expand the grid. And congestion costs warrant building new projects to alleviate that congestion, we will do so.

MR. SKOWRONSKI: I'd like to go back to the RTO and make a comment and address it to the Commission. On behalf of Duke Solar we are knocking on doors to sell green power, solar thermal. And we've talked to some IOUs and the munis and we got a couple pushbacks from the munis that this transition going from ISO to RTO is creating a little bit of uncertainty which results in hesitancy which, in my view, results in delay of trying to get some PPAs for green power.

So just make a generalized comment that there is this perception of uncertainty in the buyers in the market. So, that's it.

PRESIDING MEMBER BOYD: Other questions, comments from the audience? Comments amongst members of the panel? I guess Dave will never get our question answered as to what really happened to that first Path 15 project. I'm still waiting, trying to understand why a state-sponsored collaborative, state-run with its partners' effort, crashed and burned. But maybe some day.

MR. SABET: I wasn't involved in that circle.

PRESIDING MEMBER BOYD: That wasn't a question; that was a political statement.

MR. SABET: But I really think the root cause of all this is lack of certainty. You know, when we say certainty, you know, what Dave termed assured delivery means cost-based transmission that you can plan on for forward purchases. Very very plain English.

As long as I think the ISO or RTOs can assure people, I think there's going to be harmony and people are going to be able to step up to do what they need to do.

But right now there is a big shadow of uncertainty over the RTO because of that. How would the cost shift basically manifest itself once you merge, you know. We have had -- we have been -- over the ISO change for five years now. We haven't straightened that out.

You basically take 15 or 16 western state and form an RTO, geopolitically that's going to be almost beyond human comprehension.

PRESIDING MEMBER BOYD: Well, at that moment in time the nation-state of California was just trying to figure its own Path 15 problem out, so --

MR. SABET: I have submitted all along, this is my personal opinion, nationalizing the grid probably the easiest way to deal with that issue.

PRESIDING MEMBER BOYD: Well, thank you, all.

MR. ALVARADO: Commissioner, we have heard two legs to the stool already, the resource -- generation assumptions and we talked about transmission.

The third leg of the stool is going to be natural gas. I don't know if you want to take a short break before we move into that or just --

PRESIDING MEMBER BOYD: I would just like to press on. If people in the audience need a break --

MR. ALVARADO: Plow on through.

PRESIDING MEMBER BOYD: -- they can just step out and breath the cold air in the atrium out there.

MR. ALVARADO: Okay, well, Mark DiGiovanna is going to talk about natural gas.

MR. DiGIOVANNA: Good afternoon. Remember me? Dim the lights here.

Now that we've reached the halfway point in today's discussion, if anybody wants to stand up and stretch their legs, feel free.

Once again, my name is Mark DiGiovanna. I'm in the Energy Commission's natural gas unit. And today I'll be talking about natural gas infrastructure.

Based on the natural gas units 2002 staff report entitled, the natural gas supply and infrastructure assessment, we concluded that the primary growth in natural gas demand over the next ten years will come from electricity generation demand, or electricity generation.

So, as far as making assumptions about what kind of infrastructure additions will need to be made for natural gas over the next ten years, it's really more appropriate that we wait and get the input from both Lynn Marshall's presentation yesterday on demand and Dave Vidaver's presentation this morning on what electricity generation capacity additions are going to be made in the next ten years.

So, based on that, my presentation today really won't focus so much on assumptions that we're making for the next ten years, but will be a little bit more kind of retrospective about the type of infrastructure additions that have been made for natural gas over the past couple years, and which ones we know; we have names for project and we know they're in the permitting process or under construction and will come onstream over the next few years.

And just to let you know that the more detailed approach of making these sort of assumptions for the next ten years will be done in the natural gas unit's report which will come out in April of this year, which is the 2003 natural gas market outlook.

So today's discussion will focus on the interstate pipeline projects, broken up into the three corridors, which I will describe shortly; California's interstate pipeline infrastructure; our instate and one out of state now natural gas storage facility; and the possibility of LNG playing a role in California's natural gas supply.

All right, starting out with the southwest pipeline corridor. California receives its southwest gas primarily from the San Juan Basin with additional supplies also coming from the Permian Basin, and to a smaller degree from the Anadarko Basin.

These supplies are moved to California via pipelines owned by three different companies. One of them is El Paso Natural Gas Company, whose system is these purple lines here. I know your copies aren't in color, so here. Transwestern Pipeline Company which is this blue line up here. And Questar Pipeline Company which owns the Southern Trails Pipeline, which is right up there;

the brown line up on the screen.

Since 2002 there have been several upgrades to the pipelines on these systems. The first of which was on the Transwestern system, the Red Rock expansion. This increased delivery capacity to California by 120 million cubic feet per day. And this was completed in June 2002.

The Questar-Southern Trails Pipeline is actually an old oil pipeline that was converted over to natural gas. And that has a delivery capacity of 80 million cubic feet per day to the California border.

Another conversion oil pipeline is the El Paso-All American Pipeline, which actually runs along the southern system on the El Paso system. And that is capable of delivering 230 million cubic feet per day.

There are two additional projects that are actually -- one is actually under construction, and there's another one that just is before the FERC right now and that is the -- the one before the FERC is the El Paso-All American expansion, which is on the same route that I just showed you. They're going to incrementally add about 320 million cubic feet per day between

February 2004 and April 2005 to that pipeline.

The other project that El Paso has is also on the All American, but it's actually on the California side which this map actually really doesn't show it, but it's down here at Blythe and it will go up to Daggett. And there will be about 700 million cubic feet of capacity on that pipeline, but it's really going to be more for flexibility, to be able to move gas between El Paso's southern system and up into the Kern-Mojave area, or to move gas back, if they want to move gas from the Kern River back down to the Blythe area.

MR. TOMASHEFSKY: Mark, I promised I wasn't going to ask you questions, but I am retracting that. So you'll have to indulge me here. The two El Paso projects, are they currently in construction, or are they -- looking at the 320 and the 700. Are those currently being constructed, or are they --

MR. DiGIOVANNA: The 700 is currently under construction from what I -- the California lateral?

UNIDENTIFIED SPEAKER: The California lateral --

MR. DiGIOVANNA: Consult the Yoda of --

MR. WOOD: I just had a discussion or an email from El Paso today, because I asked them yesterday, what was the status of that. They apparently have cleared all of the routing requirements associated with converting that portion of the El Paso line between Blythe and Daggett. So they're now in the process of developing their filings to FERC.

Capacity on that line, they think, will be between 300 and 500 million cubic feet per day. And it will take them about 12 months to go through the process. And with a price of around 15 cents.

So, it's not under construction yet.

MR. TOMASHEFSKY: But given El Paso's financial situation, that's still more likely to go than not go?

MR. WOOD: I would say so.

MR. DiGIOVANNA: Okay, in this next slide what we've done is we've -- this is based on 2003, 2008 and 2013 bars here are based on results from the 2002 report that just came out in December.

And what this graph is attempting to

show, if you look at the black bars, is the current capacity on different areas in the southwestern pipeline corridor. EPS is the El Paso southern system. Havasu is the Havasu crossover which allows gas to be moved from the El Paso northern system to the El Paso southern system.

The third column there, where it says EPN-TWR-ST, that is actually the combined capacity of El Paso's northern system, the Transwestern pipeline and the Southern Trails pipeline. And then finally the last is the San Juan crossover, which is the -- going back here, this end of the El Paso northern system. It primarily flows from west to east.

So what this chart is showing is that based on the projections from the 2002 report, if as much gas is going to be demanded in these pipeline corridors were to flow on these pipelines, this is how it compares to what the current capacity is on each of those areas.

So as you can see, in 2003 and going forward, I mean there's actually more gas that's going to want to flow there than there actually currently is capacity. So there will be a need for capacity additions as we move forward. Some of that is being addressed right now with the capacity additions that are underway, or at least in the permitting process.

MR. TOMASHEFSKY: And that goes back to feeding generation growth in Arizona, then, primarily? You start looking at that, you're looking at 10,000 megawatts, depending on what the assumptions are in terms of added power generation in Arizona, you'd expect that that's really the only game in town to serve it. So therefore you get that increase in capacity --

MR. DiGIOVANNA: Right.

MR. TOMASHEFSKY: So, can you tell how much of that is targeted to California?

MR. DiGIOVANNA: How much --

MR. TOMASHEFSKY: Just off hand, and I recognize that we're going to update that forecast. Do you know that, Bill? Going to get you to keep coming up.

MR. WOOD: Basically all of that new expansion is to meet east of California requirements. Our forecast that based upon the demand that we were using as of last year, indicated that California's demand for the southwest is going to be rather level for the next ten years. There'll be a little growth and a dip, but it's pretty much going to be constant.

So therefore, all this demand then we see is basically to meet the growth in two areas. One is the big growth in power generation in the Phoenix area; and the other is to meet the demand on the North Baja pipeline.

MR. TOMASHEFSKY: Okay, so that flows then, then it follows with that logic that Kern River then provides the incremental supply into southern California?

MR. WOOD: That is correct.

MR. TOMASHEFSKY: Thank you.

PRESIDING MEMBER BOYD: Bill, don't sit down. The lay person would look at this chart and say, gee, three out of the four trails you're talking about here, or pathways, we're in trouble this year. But I don't hear any hand-wringing over that interpretation. Comment?

MR. WOOD: I'm sorry, you said they were in trouble --

PRESIDING MEMBER BOYD: Three out of -- in three out of the four examples there, the capacity's exceeded.

MR. WOOD: This is for -- well, our forecast is indicating here for the year 2003.

PRESIDING MEMBER BOYD: Right.

MR. WOOD: Again, --

PRESIDING MEMBER BOYD: We're in 2003.

MR. WOOD: Yeah, well, again --

PRESIDING MEMBER BOYD: The price of gas is out of sight.

MR. WOOD: -- it has to do with the --

PRESIDING MEMBER BOYD: Et cetera.

MR. WOOD: That's right, we are in 2003 now, aren't we.

(Laughter.)

MR. WOOD: Well, the year's not over with yet, so --

PRESIDING MEMBER BOYD: Yoda, are you worried?

(Laughter.)

PRESIDING MEMBER BOYD: Okay.

MR. WOOD: The implication is, again, we're using a long-term forecast to try to indicate what's going on in the short term. And, what we're trying to indicate with these are not absolutes, but the need -- but the indications of where new transportation requirements are going to develop in the near term.

The Havasu crossover, for instance, we're seeing that it may have to increase about three times its current capacity, given the way the model operated. And that indicates there's a tremendous amount of growth required in that area. Well, it depends upon how fast those generators get built and when they come on, as to what kind of impact that's going to have on the Havasu crossover.

On the other hand we didn't model this, but this is one of the things that we want to do, is that El Paso south, as you can see, is running under capacity the way our model operated. And also the All-American pipeline is being built, which is also adds onto the El Paso. So we may have up to 500 million cubic feet per day of additional capacity on top of what we show here.

Now, if the expansions do not occur on Havasu and on the northern El Paso system and Transwestern and Southern Trails, then that will then force the market then to have to go to the Permian, which our model indicates they do not want to do, because the Permian, actually prices there, as we know, are impacted by what's going on to the east. And therefore the Permian tends to be a higher priced gas than the San Juan or the Rockies gas, which the model is trying to feed here.

So, if that capacity isn't built on the northern system to support the demand that we're talking about in Phoenix and in the North Baja pipeline, then it'll be interesting to see what happens as regards to utilization of the southern system relying on the Permian facilities, and what kind of impact that will have on prices in California.

We haven't run it, but my first inkling is if that were to occur that the prices in California will go up.

PRESIDING MEMBER BOYD: Thank you. I wanted you to say that because were I a lay journalist and saw this I would run out and write an article about we're in big trouble already. So, I wanted you to put the caveats on that. As Bill knows, some of us sit down with he and a whole bunch of other people every other week in a group called the Governor's Natural Gas Working Group, and talk about all these kinds of things.

I wanted you to share some of that with

a broader audience. Excuse the interruption, Mark.

MR. DiGIOVANNA: That's certainly all right. The next pipeline corridor I'm going to talk about is what we call the PG&E-GTN pipeline corridor. Mainly because they're the only interstate that actually serves us through that corridor.

And this is California's source for Canadian gas. And it also could provide us with some Rocky Mountain gas if it were to flow on the northwest pipeline in background. But primarily when we think about PG&E-GTN we're talking about California's supply of Canadian gas.

And GTN did have an expansion between November 2001 and November 2002; it was actually in two phases. Added 211 million cubic feet per day of capacity. And similar, Scott, to what you were asking about in the southwest, that expansion was actually to serve electricity generation demand up in this area. But by making that expansion, it did benefit California by allowing gas to still flow to the northern California border.

There is one other expansion that didn't really have a huge effect on California which was the Tuscarora pipeline, which takes gas from Malin and delivers it to Reno. You know, there may be some small benefit for California for serving like the Lake Tahoe area, as well. Just thought I'd mention that.

And in similar fashion, the black bars again represent the current capacity with the expansions that I just mentioned. So, again, we can see here that actually by the time the -- when we're looking at the California border capacity, we're actually, this would indicate that we're doing all right there without any further expansions.

Okay, the last interstate pipeline corridor that I'm going to talk about is the Kern River pipeline corridor. The Kern River natural gas pipeline serves California its primary source of Rocky Mountain gas. There have actually been several upgrades that have taken place on this pipeline, and another very big one planned for this year.

The first one was the emergency expansion which added 135 million cubic feet per day of capacity in the summer of 2001. This would have been right at the height of the energy crisis. And the following year in May of 2002 that expansion was actually removed and replaced with a larger 146 million cubic feet per day permanent expansion.

More importantly, Kern River is in the process of adding, more than doubling the capacity on that pipeline, adding 906 million cubic feet per day to their pipeline, which would bring their total capacity to around 1750 million cubic feet per day. So that is a very significant expansion.

One other addition here; it really doesn't have anything to do with interstate capacity additions, but it is on the Kern River pipeline, is the High Desert lateral, which takes gas from the Kern River pipeline for delivery to the High Desert Power Plant, which is scheduled to come online this summer.

And now looking at Kern River their current capacity right now about 845 right here; that's obviously going to get into here, so we'll be doing all right for a little while. But because of the relative low prices in the Rocky Mountain region, there is going to continue to be increased demand for Rocky Mountain gas to

California. So, you know, there will be demand for either further expansions on the Kern or further capacity capabilities of delivering gas from the Rocky Mountains, whether it's Kern or otherwise.

All right, moving to the intrastate pipelines. This is a rough schematic of the PG&E system. PG&E has made one expansion, one fairly large expansion in the past year and that was the Redwood Path expansion, which was around this area up here. Increased capacity, receiving capacity from the northern California border by about 179 million cubic feet per day.

Just want to point out that the PG&E system does have unique capability, compared to the other major utilities in California, is that it can actually take gas from all three of the intrastate pipeline corridors directly through Kern River, the southwest and also from the PG&E-GTN.

MS. BAKKER: Mark, would you mind showing me where the storage facilities are on that map there?

MR. DiGIOVANNA: Okay, I have a better one coming up, but --

MS. BAKKER: Okay, okay, well, let's wait then. I'm sorry.

MR. DiGIOVANNA: Okay. Kind of in the spirit of what we were doing with the interstates, just want to show you here this is also based on the 2002 natural gas supply and infrastructure assessment. And this is just to back up what I mentioned at the beginning of this discussion, that this is the demand by sector versus the receiving capacity in the PG&E system. And this is just to show that the largest and most rapidly growing sector in there is electricity generation.

And on to the Southern California system. Now, Southern California has actually made several expansions since the energy crisis back in 2000-2001. The majority of them are to increase the receiving capacity into its system. Plus there's one additional one that actually increases its capability to deliver gas to the San Diego system.

The first of which is the Wheeler Ridge expansion, which increases capability by 85 million cubic feet per day to take delivery from California instate production and from Kern River and PG&E. That was up in here.

It also increased the North Needles compressor station so that it could increase its receiving capacity off the Transwestern system by 50 million cubic feet per day. And this is right up here by the southern California border.

It completed the Kramer Junction interconnect which was a 200 million cubic foot per day expansion, which allows it to take gas off the Kern River pipeline right over here at Kramer Junction, down onto its system.

And finally, the Line 85 Sylmar compressor station expansion, which increased its capability by 40 million cubic feet per day to take deliveries from California production.

And then the last one is the Line 6900 upgrade which was right down in this area. And this here was -- right now San Diego, the San Diego Gas and Electric system does not have a direct connection to any of the border delivery points, so when it receives gas from the interstates it actually has to do it through the southern California system. So this actually increased its capability to take interstate pipelines.

And one thing that I didn't mention

before was the completion of the North Baja pipeline along the southwestern corridor.

Also, remove some demand from the San Diego area, so that -- because the northwestern Mexico was receiving its gas via the San Diego system, which was, of course, receiving it through the Southern California system. So, the completion of those two projects both took some demand out of the San Diego area, plus gave it some additional capacity to bring gas into its system. So that will definitely benefit the San Diego area.

And just like in the PG&E area, the electricity generation demand is the fastest growing segment of demand.

For you, Susan. Another way that California can improve its infrastructure is, other than being able to bring more gas into the state, is to be able to keep more gas in the state. You know, when we have low demand periods and then use it during high demand periods.

And California has undertaken a couple projects, and will undertake a few more to increase its capacity to do this.

The first project was in the southern

California area, and this was at the Aliso Canyon and La Goleta storage facilities. And these are down here, number 6 and 8. And these were existing facilities that in the summer of 2001 they were able to convert some of the cushion gas in the system to working gas. So it actually increased the capacity combined between the two by 14 billion cubic feet.

The next big addition for California was the Lodi; Western Hub's Lodi gas storage facility, which began operation in effectively January of 2002. And that added another 12 billion cubic feet per day -- or not per day, billion cubic feet of storage capacity in northern California.

And then in the coming years both PG&E and EnCana at Wild Goose will increase, have expansions of their facilities that will increase the storage capacity in northern California by almost 22 billion cubic feet.

And then the last project listed here is the one out-of-state project which the Red Lake storage project. And that project right now is, it just received its approval from FERC based on non environmental review. So it's still pending environmental review. But that will -- the storage capacity there will be to serve east of California demand, but it is also -- there is some storage that will serve California customers, as well.

So just having the storage near the border to serve regions that would otherwise be demanding, you know, competing with California for demand on the pipelines, plus also serving some customers in California will benefit the state.

MR. TOMASHEFSKY: Is it tied just directly to Southwest gas, or Kern River, as well?

MR. DiGIOVANNA: It's actually going to be connected to the El Paso northern system. It's kind of hard, without the pipelines there --

MR. TOMASHEFSKY: Okay.

MR. DiGIOVANNA: The last slide. I know there's been a lot of press about the possibility of LNG becoming a supply source for not just California, but for the western side of North America, considering there are no terminals right now.

Right now the three terminals that I've included in this graph are the three that have actually filed permits with the Mexican authorities to build projects near the southern

California border with Mexico. All in the Baja region.

The likelihood is that not all three of these would, you know, if they were permitted, would be built. And there are also -- there are proposals to still try to build a facility in California. But none have gotten this far as actually filing for permits as these ones have here.

And with that I will open it up to questions.

MS. BAKKER: I have a couple of questions. Your two graphs that show the receiving capacity compared to the demand. And if I understand the graph correctly, the demand is expressed in an average sense, an average daily demand.

Have you looked at how that compares to a peak demand?

MR. WOOD: Basically what we're trying to show with this map or this graphic, we show the receiving capacity and the annual average demand in regards to millions of cubic feet per day. The interesting thing when we put this map together, or this graphic together was to try to indicate what kind of slack capacity there might be on the system. Slack capacity is thought to be that in order to meet the seasonal requirements your slack capacity on annual average basis should be 15 to 20 percent.

And what we were trying to indicate here was that for the SoCal system currently, given the huge amount of additions that they did to their system in the last two years, that they're now, their slack capacity is somewhere in the area of about 40 percent.

And that by the end of our study period that we have here they'll be down to about 20 percent. So therefore they have basically built in the capacity.

If you were to use a slack capacity factor of 20 percent as a rule of thumb to shoot for, that's what this graph is trying to indicate to us. If they hadn't added that on, then they would have been in the same situation as PG&E --

MS. BAKKER: I understand that, but I guess I read your report and one of the things it said was that the PUC had established the 20 percent figure.

MR. WOOD: Yes.

MS. BAKKER: And it used average temperature. And hydro, average hydro, average temperature. And the question I had was have you looked at that 20 percent criterion that is the planning level you would shoot for, or using that receipt capacity, actually, against a peak day in an extreme set of assumptions.

MR. WOOD: Well, we have not looked at it specifically in that regard. And our concern would be not so much associated with a peak cold day requirement or a series of days that were cold in the wintertime, because storage would fill into this.

Demand, for instance SoCalGas currently, as their capacity, receive 3800 million cubic feet per day. In addition they can pull another 3000 cubic feet per day out of storage. And you put this all together, they have the ability to meet about 6 billion cubic feet per day of demand on their system. They've only hit that or come close to that once or twice.

MS. BAKKER: But we've had a change in structure. You've said it over and over again, from the first person that stood up here to the last, that now natural gas demand is driven by electric generation. The change in natural gas demand.

So, what I think could be happening, I don't know for sure, because I haven't seen numbers, is that we have now two peaks, two times when we need to rely on storage instead of one. And if that's the case, we may be facing new challenges.

MR. WOOD: Well, there's always been two peaks. And it's always been that the winter month is a higher peak than the summer month. And --

MS. BAKKER: But we don't know if that's going to continue with the change in electric generation.

MR. WOOD: We have -- well, to some extent David Vidaver has provided the hourly and weekly, and we have looked at, at least in the summertime, what that peak requirement is. And we've always had sufficient capacity to meet that particular requirement.

The problem is -- well, to boil it down to -- I'm not going to go into this any further, but the thing is, yes, we need to look at that. That's one of the things that we want to be looking at during the remaining portion of our period between now and April. We're hoping to be able to have the time to be able to look and look at that. If not, then we may have to put off that until the next round when we do it.

But that is definitely something that I've wanted to look at for the last four or five years. And we just are in the process now of developing the tools to be able to do it.

MS. BAKKER: It takes a lot of extra assumptions probably to do that.

MR. WOOD: Well, for one thing, our demand office only looks at annual gas demand forecasts. And we need from them the peak requirements, peak day requirements so that we can -- and they don't do seasonal forecasts for us, they only do the annual. So we need a seasonal forecast. We can develop one based upon the historical shares --

MS. BAKKER: Records, yeah.

MR. WOOD: -- for each month. But we haven't taken that step yet. But we may have to do that.

MS. BAKKER: Thank you.

MR. TOMASHEFSKY: What that really shows, that's part one of the puzzle, is that there's this receiving capacity question. And then you have actually delivery capacity is another question.

MS. BAKKER: Right, that's --

MR. TOMASHEFSKY: So if you look at that as a peak --

MS. BAKKER: -- that's not something we've even looked at here, right?

MR. TOMASHEFSKY: Right. So, from a standpoint of SoCalGas' claim that they haven't had a curtailment, well, they haven't technically speaking because they really ramped up capacity, delivery capacity to almost 7 bcf a day. So by virtue of doing that you have slack capacity.

Now how you define that on an average day or a peak day you have to really give it a lot of thought as to how to present it.

MS. JONES: Well, there's also some pretty severe cost consequences associated with running up at those levels, as we saw in 2000 and 2001. So it seems that that's a very important contingency for the Commission to be assessing.

MR. ALVARADO: Well, I'd like to also add, Susan, to your question. I think that is part of the game plan. David has explained some of the different scenarios we want to try to evaluate. At least from the electric generation side we will consider some of these low hydro scenarios and see what would be the consequence of fuel demand for electric generation.

That piece will then be passed on to the gas folks and hopefully they can evaluate to see what the implications are to the gas system, too, as part of our integrated part of the report here.

MS. BAKKER: Right.

PRESIDING MEMBER BOYD: I'm looking forward to that. I'm even looking more anxiously forward to when you start adding in supply potential and where it might all come from once we decide demand and the capability of the infrastructure, intrastate and interstate, to move gas around. I want to know is it even there. Or what do we do. So, April is going to be exciting.

MR. PRUSNEK: My name is Brian Prusnek from the CPUC. Also in answer to your question, Susan, yes, that is the receiving capacity of the utilities there, for example, what they've been showing.

And I guess the question is on a peak day is there enough, and this is what we kind of got into, is the deliverability there to get to it.

The instate aspect of it is CPUC does require the utilities to have their natural gas pipelines built to serve an abnormal peak day on a cold winter day --

MS. JONES: But that's only for the core customers, correct?

MR. PRUSNEK: Well, that's how large their pipelines have to be built to serve the core customers. And we have imposed some of those conditions, or stricter conditions, on the southern California systems.

But there's also --

MR. TOMASHEFSKY: Based on the --

MR. PRUSNEK: -- curtailment, then. If we start pushing into the core customers we also have curtailment rules in which the core customers can curtail.

But on peak days we also have the ability to pull gas out of storage and there's also 15 percent of our gas consumption is from instate production, as well.

So the question really does go to can the intrastate pipelines deliver that. And unlike instate where we can require slack capacity, especially on the receiving end of the pipelines, the interstate, we would have to actually pay quite a bit for that. And we would have to sign up for that capacity, to get that equivalent slack capacity there.

So the question is do we have the people there to sign up for the intrastate capacity to be able to get that peak day delivery. And I would be pretty sure that the companies that need to take gas off the interstate pipelines are taking enough to meet their peak day needs.

MS. JONES: Well, I think there's an important caveat that you have to talk about when you talk about the intrastate system and storage. That's assuming that the storage is there.

And we've had circumstances where the storage was used and not available when we had peak demand conditions.

MR. PRUSNEK: Correct, and --

MS. JONES: So it's not just the storage capacity, it's whether there's conditions that are conducive to putting the gas in storage and --

MR. PRUSNEK: That is correct. And we have imposed certain storage obligations upon the utilities for their core customers. Noncore customers can do whatever they want with the storage. And that's a question we need to look at potentially in the future.

MS. JONES: I think one of the important things for us, in terms of looking at the largest part of the demand growth in natural gas use is the electric generators, and they are not part of the core. And so how do you adequately plan for them and their needs?

MR. PRUSNEK: That is --

MS. BAKKER: Right, so it doesn't do you much good if you're curtailing electric generation so people can't run the fans on their heaters, to have gas. So, you got to cover the whole picture.

PRESIDING MEMBER BOYD: Well, here we are again where we were two years ago --

MS. BAKKER: Yes.

PRESIDING MEMBER BOYD: -- to see if the people are going to put gas in storage starting March and April, with the prices where they are. And, you know, having been burned before that with, as already said, no gas in storage. So watch this moving target.

MS. BAKKER: Thank you.

MR. ALEXANDER: Michael Alexander with Southern California Edison Company. And I just wanted to, while we're on the subject of storage, point out that although we tend to think of storage mostly in terms of this graph of average or peak day delivery, it's also important to realize that it's a key component of managing a system in terms of balancing, in terms of price control and everything else.

And it's only kind of been talked about in the report, which is a good report; this isn't criticism, it's a suggestion, as a substitute for immediate end-use delivery. But I think we have to, in order to really look at the system, look at its use for price control and for balancing, as well.

And it may require a very different set of assumptions as electricity grows than we've used in the past.

MS. BAKKER: Good point.

DR. ARTHUR: Dave Arthur, City of Redding. It's very instructive to compare the opportunities that are available on gas and also look at what has happened in gas transmission to the electricity side.

And earlier I think I used the term friction. On the gas side if you feel you need assured delivery, you can go out and become a shipper. Now, in the case of getting from Malin to the Canadian Basin, you can become a shipper for 20 years or longer.

In the case of California the current limit is one year for assured, which is a source of grave concern to us. But to their credit, PG&E is making a number of constructive suggestions in their most recent gas court filing and hopefully we will make progress in that direction.

Now, what's really interesting is if you become a shipper, that is to say you pay your pro rata share of the entire cost of that pipe, you actually get to use it. Which is actually very typical within the normal commercial world.

But if we go over to the electricity side, if you pay your pro rata share of the transmission system, which all end users do under the current model of California, what it does is it gives you the right to bid to use the system.

Be kind of like going to an airport and you paid for the ticket and you get there and they say, you're now entitled to bid to see whether or not you get on the airplane or not. Which, of course, is not the way it works; if they've over-subscribed the airplane they have to pay you to not get on the airplane.

So I think it would be helpful when we create the baseline to point out the fundamental distinctions that exist in the gas world and in the electricity world. And as we look at policies to eventually consider and to recommend to the Governor, it seems to me that we might take a lot of lessons from the gas world.

We might note that expansion has actually been going on in a very regular basis in the gas world. You saw a list of the number of actual expansions that have occurred in the gas world. I can assure you you will not find those same number of actual expansions in the electricity transmission world.

And you will find that those are purely cost-based expansions, which helps keep the cost down, assurance up, and again leads to lower prices for the retail customer.

And then the last point I'd like to make is using the City of Redding as an example, we are a classic case of the inseparability between gas and electricity, because we have just completed a new power project within the city limits of Redding, which, under certain circumstances, could provide anywhere from 50 to 75 percent of the electricity required by the citizens of Redding at a moment in time.

That plant runs on gas. As you just heard, the planning criteria have been to take care of core. Those core people that are being referenced are also electricity consumers. And in order for them, as was astutely observed by the Commissioner, in order for them to run their forced air gas heaters, they're going to need electricity.

And so the notion that we can treat core and noncore somehow as distinct entities is, I think, probably appropriate to times past, but may not be appropriate as we go forward. And so I hope that again we will look at the sort of inseparability of gas to electricity.

And just as an aside, Redding got very involved in gas because as you go to gas-fired generation you discover that the costs of gas become your single largest cost of providing electricity to your consumers. So it becomes an issue of enormous importance to you.

And so we no longer see them a separable. But what we have discovered, because we're new to the gas business, frankly, we've discovered that while all of this restructuring that we've heard about was alleged to be replicating what went on in gas, we've discovered that there's very little relationship to the restructuring that has gone on in electricity, and the restructuring that's gone on in gas.

Gas actually is fairly logical. In our view, electricity is not.

MR. HALL: Hello; my name is Stephen Hall. I'm not representing anyone. My background is I've been in efficiency and renewables for 22 years.

And what you've presented here today is essentially a model that says that you're going to meet natural gas demand through expanding natural gas supply infrastructure.

And I wondered if the Commission has done any analysis to look at supplying natural gas infrastructure by suppressing demand, by making natural gas energy end uses more efficient. That is to say making our furnaces, our water heaters, our windows, our boilers, our cogeneration systems more efficient.

And what that would translate to in the number of pipelines, storage facilities and so on, that would be avoided by making those end uses more efficient.

For example, we have about 6 million furnaces in northern California that could be improved by their end use efficiency by 40 percent. We can immediately improve the gas water heater efficiencies by 20 percent by commercially, off-the-shelf technology. And we could do this with windows, boilers and cogeneration systems.

And I wondered if the Commission had done any analysis on the demand side that would show what the equivalent impact would be on the natural gas system.

MS. BAKKER: I saw Lynn Marshall in here earlier; I don't think she's here anymore.

MR. WOOD: I know that we have one division and one office in that division that is specifically involved with developing conservation. I think the State of California is the lead with regards to imposing conservation into our systems, both in regards to appliance standards and building standards.

For your information, I have tracked the average utilization of a residential home since 1965. In 1965 the average home used about 125,000 cubic feet per year. The most recent information I saw indicates that is now at 55,000 cubic feet per day (sic).

So, while residential hookups continue to grow, the utilization per household has continued to drop. As a result you can see the residential demand here is fairly constant, both for SoCalGas and the PG&E service areas; indicating, yes, the conservation standards that the Energy Commission put into place and have been putting into place since its inception, 1975 or '6 timeframe, has had an impact both on the building stock that is being brought into California, as well as those appliances that are being used within the state.

So, yeah, I think we have taken those kinds of things into account to trim things further down. Then at the 55,000 cubic feet per home, would actually then have to require going in, I think, and doing retrofitting of the old stock requiring things to be done. The old stock meaning the old homes.

I think for the most part, I don't know what the life expectancy is for furnaces and for air conditioners and for other hot water heaters, but basically most of that sort of stuff will be phased out. The old stuff, the old inefficient units are being replaced by the more efficient units.

Now, there is a range. You know, if you want to put in a new hot water heater there is a range in terms of how efficient each of those units are. But overall they are in better condition than they were, the original stuff that was put in the home. In addition, our requirements are much higher than they are anyplace else in the nation.

MS. JONES: Well, I think the gentleman does have a very valid point here. Yesterday when we talked about the electricity demand, we looked at the things that we, you know, expect to occur that are included in the demand forecast; and had a discussion about additional energy efficiency opportunities that might be available to defer investments in power plants and other things.

And I think it's valid to ask the same

questions on the natural gas side. Are there additional opportunities for energy efficiency that mean that you can defer investments in natural gas infrastructure.

MR. HALL: Yeah, I mean what I'm basically suggesting is that rather than making energy policy on the basis of your helplessness in terms of demand forecasts and scenarios, that you can make conscious decisions which you can control to turn over the furnace and water heater stock.

I mean the Commission turned over the refrigerator stock over the last 20 years very successfully. And if a program was put in place, you could turn over the 6 million furnaces in northern California and immediately realize a 40 percent decrease in gas demand in the residential sector.

PRESIDING MEMBER BOYD: I was going to answer your question with a simple yes. But it deserved more than just that. And I'm glad Bill stepped to the fore. I think --

MR. HALL: So will it be possible to see an analysis on the demand side?

PRESIDING MEMBER BOYD: Well, I'm not going to --

MR. HALL: Of natural gas.

PRESIDING MEMBER BOYD: I think that's something we want to do. I think, you know, there's a heavy dedication in this agency now to efficiency. And that's a very logical question.

And as we go through the iterations we'll see, although I see the Project Manager standing at the microphone and she may have an opinion here.

MS. GRIFFIN: The answer is yes. This is another problem of right now we're just sunshining bits of the pieces. There's a whole other section which is working on the energy efficiency potential, the cost effective potential.

And one of the primary policy questions which was brought forth by the Commission in its scoping order, and that we're working on, is is there a level of energy efficiency which we would like -- which the state would like to set as a goal in terms of doing that first.

So, it's definitely the idea that we've now identified a renewable portfolio standard, that in terms of doing that first on the generation side. Now the question is even before we do generation should we be doing something more explicitly in energy efficiency and demand response.

Another wave of people; another wave of reports in May. So, yes, we're definitely trying to meet the concern you've raised.

MR. HALL: Okay.

MR. HALL: You know, I'd like, in terms of recommendations that you want to come up with, the five or six or seven major things that you'd like to come up with, I'd like to suggest that you look at establishing a least total cost integrated natural gas resource plan that's based on a dispatch order of energy efficiency, renewables and down the line.

I've addressed the energy efficiency part in this section, but I have lots of comments about renewables versus gas combined cycle for the next section.

PRESIDING MEMBER BOYD: Thank you.

MR. HAMPTON: Good afternoon; my name is Kent Hampton; I'm with Marathon Oil Company and I represent one of the companies that is proposing to bring LNG into Baja.

It appears throughout these

presentations that California is increasing its dependency on natural gas; that coal, oil and nuclear power is certainly not in favor.

As a gas peddler I think that's a great thing. But, as a public policymaker that's probably not a good thing.

And that raises, to me, the importance of a diversity. If we're going to put all our eggs in the natural gas basket, diversity of supply, and speaking not just for our project, but for any of the LNG projects, that's really one of the services that they would provide. Another source of gas.

And probably that source would come from South America, from Alaska or from Southeast Asia. The spikes that we've seen here recently that Bill talked about are evidence not of just a California-centric problem, but it's a bigger problem now. We're having some deliverability problems in the lower 48 and the traditional basins of Canada.

So, to me, I think you have to look at LNG as not just a gas supply, but as some diverse sources. Another way of perhaps controlling your dependence on natural gas, traditional natural gas.

Lastly, I wanted to point out we were talking -- Mark was talking about storage. One of the other things that LNG brings is storage. We would have, and I'm sure the Sempra and the Chevron Texaco projects and Shell projects will all have storage onsite, 6 billion cubic feet. It's very high deliverability storage.

And that's not something that usually strikes people when they think about LNG. But it has the ability to meet load very quickly.

Thank you.

PRESIDING MEMBER BOYD: Thank you. Those of us who follow this very closely are aware of all that you said about LNG. We've barely touched the surface. I'm expecting when we get to the supply discussion there will be a lot more talk about LNG. There certainly has been a lot of talk about it within the halls of this building in the past many many months. But I appreciate your comments.

There's a lot of friction, to quote the gentleman in the audience, associated with LNG; more friction north of the border than south of the border of the Californias, so it's a hurdle to be dealt with.

I look at LNG as kind of the big pipeline from the west. And if the pipelines from the east don't respond to need and we can't reduce our demand all the way through efficiency, then, yeah, we need a supply.

MR. MELDGIN: I want to rephrase a question of Susan Bakker's, I guess. One way of looking at that is given the growing demand for gas or electric generation, the risk of drought and so on, what's the appropriate level of slack capacity. Maybe a different number is appropriate now.

And awhile back the CEC had a report; Dr. Weatherwax was here talking about running different temperature and precip scenarios around a basecase for some future year. And then somehow integrating gas and electricity to get at that question. I'm just wondering where that whole effort stands.

MS. JONES: Well, it's an area of active interest for this Committee.

PRESIDING MEMBER BOYD: Yes.

MS. BAKKER: Yes.

PRESIDING MEMBER BOYD: Well, the

Electricity and Natural Gas Committee on which I sit is very interested in that, but some staff member can perhaps --

MR. ALVARADO: Well, I know that among staff we -- you know, I know there has been meetings and Mark has come to talk to us. And we are trying to examine different capabilities that we can engage in that kind of effort.

Considering I wasn't part of that discussion, sorry, I don't really have an answer. But it is something that we'd like to consider.

PRESIDING MEMBER BOYD: Well, let me just assure the gentleman that there's been a lot of talk about it, an extreme amount of interest in it, a very keen desire to engage deeply in doing that. And right now I'm sure we're bumping up against resource constraints, both person power, of which we can't get any more of, and this budget situation, and dollars, which we can't get any more of.

So we will be balancing our resources against the workload we face, as well. But, yes, some of us are very interested in that. I mean it's just part of looking at the whole system. If you're in the 21st century you've got to look at the whole system and all the components thereof. And it's a struggle.

MR. PRUSNEK: Brian Prusnek from the CPUC. One last comment I'd like to make. I would like to congratulate the gas group. The CPUC and the CEC do work quite a bit in the field of natural gas together. And I would like to publicly congratulate the CEC gas group on their efforts they have been doing on this.

You know, they've been pushing out reports like crazy here recently. And they have another one coming out in April. And we look forward to reading that and helping them and commenting on that, as well.

Thank you.

MS. BAKKER: Thank you.

PRESIDING MEMBER BOYD: Well, thank you. I happen to know that, you know, when the gas group meets every other week you're there on the phone. In fact, I finally met a voice today, who I'd never met before, from the PUC, introduced herself. She's just been a voice on the telephone now for a long, long time. But, anyway.

MR. MARCUS: Good afternoon; I'm Bill Marcus, I'm representing The Utility Reform

Network, TURN. I'm here to play Mike Florio; I'm not Mike Florio. But I do have a couple of brief observations --

PRESIDING MEMBER BOYD: Let's see how close you get.

MR. MARCUS: -- on gas that came out of what I was hearing. And one of them has to do with the storage question.

One of the problems we have is that we deregulated storage in 1993, and basically we no longer have a situation where everybody in the state is responsibility for reliability. The only people who are responsible for reliability on the storage side of the world are the core customers.

The noncore customers can do whatever they want. And in the year 2000 they did whatever they wanted, which was to pull all their gas out of storage in the month of November. That's probably the single basic reason why we racked up billions and billions of dollars in debt in this state. And yet it seems to receive very little attention in the overall scheme of deregulation.

Maybe we need, if you're going to be a gas player in the state with the electric system, maybe you need to be a player in the storage system along with everybody else in the state to make sure that things are kept on a reliable basis.

Second quick observation is that we have had rate design policies for a number of years which encouraged people not to build gas. Essentially the whole marginal costing rate design practice, as done for intrastate pipelines, and this is changing with the new gas accord and a couple of things, and those changes are probably for the good, but what they basically created a situation was where the electric generators basically had to say they never needed any more pipeline. Because they would not only have to pay for what they needed, but they'd have to pay for their share of the embedded system. And they got away without paying for it for a number of years.

I think we're moving away from that. But we still have the question of essentially making sure that we build what we need, and we don't end up dumping the costs back on the core customers because they're the only ones you can force to pay for them.

And I think those are my observations for this afternoon. I'll come back when we get to cost of generation. Thank you.

PRESIDING MEMBER BOYD: Thank you.

MS. JONES: Thanks, Bill.

MR. ALVES: My name is Joe Alves; I work with BP Energy, and I've had the pleasure of working for SoCalGas in procurement for six years. And I now have the pleasure of working for BP marketing power plants. And it's a very difficult challenge.

Everybody takes risk in the market. Power plants build generation and they're looking for a long-term power contract. Producers, like ourselves, try to find natural gas. We take risks in E&P. Other companies take risks on transport and storage.

So everyone needs to share in the risk. One thing I've noticed is power plants want gas on demand.

I want to echo the comments on storage. Generally utilities go out, I'm talking about IOUS, and they pay for reserve capacity. And they pass that through in their rates.

But we see on the storage side they don't go out for capacity, nor do they want to own it. Who wants to own storage this year? This is a repeat of 2000. And I lived it in '96/97 with SoCal buying gas. I lived it in 2000 selling it.

We have backward-ization in the market which is a real fancy word that's saying that the prompt month is more expensive than the future months. So when I'm looking at buying gas at $6; paying the utilities $1 for storage; and I can't hedge it forward in the winter, I'm not going to take that risk. Neither is third-party storage holders which are -- Melissa, you brought up a great point -- that's the power plants.

So your third-party storage holders, which own about 30 or 40 percent of the storage capacity in California, don't have any incentive to store gas. So where does that put power plants? In the day market with a lot of volatility.

Jim, you brought up a good point. Looking at those transportation slides. Why isn't anybody using the south main line on El Paso? It has excess capacity. The only pipeline that has excess capacity to California per that chart.

The reason is that Permian gas is selling for a 40- or 50-cent premium to SoCal border. So here you are at BP. I'm going to buy, I'm going to take Permian gas at $5.50; I'm going to pay for transportation which is fixed on El Paso, 35 cents plus fuel. And it's going to land me at the California border at $6. When the forward market for California border is at 5.25. I can't do it.

And all the power projects, Mesquite 1 and 2, Sempra Energy Resources, their plant off Baja Norte, that's 1800 megawatts. FPL Blythe, another 500 megawatts. All off that south main line. It's very challenging to get natural gas supply.

So power plants don't have storage. They don't want to hold transportation capacity because that, over time, is a big loser. And so they're all in the day market. And you have to pay a premium in times of shortage.

And I've been to a lot of IEP meetings and Jan Smutny-Jones has said a few things that I laugh about. We have a faith-based energy policy. We pray for snow.

(Laughter.)

MR. ALVES: And then also I heard last time, last year I went -- and it's up at Lake Tahoe; you really do learn something up there.

But, one thing is, is surplus is less expensive than shortage. But it's just who pays for that surplus.

One more point that I want to make is you have the gas industry restructuring this year on SoCal. It's very challenging. You have PG&E unbundled; you have SoCal trying to unbundle. And so SoCal core is not going to be responsible for system integrity.

So they have a gas cost incentive mechanism that the CPUC loves, and it works. But if we go to this new industry restructuring, they're not going to be responsible for making sure that gas is flowing to California to meet everybody's needs to avoid curtailments, which they're very proud to say it's been 11 or 12 years since we've had a curtailment.

So, I guess my point here is I hope that the power plants and the people I market to recognize that if you don't have any storage you're subject to daily price volatility. And if you don't have any transport, you're subject to the basins volatility we've seen between the basins and the border.

It's very challenging to provide on gas

demand at a discount. And that's generally what they want to require. So, thanks for your time.

PRESIDING MEMBER BOYD: Thank you.

MS. JONES: Thank you.

PRESIDING MEMBER BOYD: Anything else, Mark? I guess we've finished this subject for this session. This is going to be a --

MR. ALVARADO: We're coming down the home stretch, because we've got one more report. One more staff presentation.

PRESIDING MEMBER BOYD: Right.

(Pause.)

PRESIDING MEMBER BOYD: Do you need a break? Let's take a five-minute break.

(Brief recess.)

CHAIRMAN KEESE: We're doing a fast shuffle. I just completed another meeting that I had to have, and Commissioner Boyd is doing a tv interview at 4:30 that he was committed to. He will be back as soon as he's off camera.

MR. BADR: Welcome back. My name is Magdy Badr. We prepared the cost of generation report. I'll be very brief because we know we are pressed for time, so I'll try to zip through this as much as I can.

The purpose of the report was several ones, actually. Basically the modeling unit, or the modeling folks, they need to have some descriptions or characterizations of the technologies we are going to use in the resource modeling. So this characterization is spelled out in the report, and basically that's what we will be using in their modeling analysis.

From time to time we have questions and we have to provide information to the Commissioners. They ask us for information about how much will it cost to build a power plant, and when the power plant or combined cycle, typical power plant combined cycle or wind or geothermal or what-have-you. So we had to prepare those information to be available for them.

The public sometimes will call us and ask for this information, as well. And basically they ask the same questions. Do we have any idea about how much will it cost for a particular generation to be constructed.

Other agency, they are also calling us like the Board of Equalization. They call us. Or the City of San Francisco, sometimes they call us for information about how much would it cost for a typical power plant combined cycle, or one of the renewables basically to be built.

Also these numbers, we feel that it might help any portfolio manager to basically screen out the resources, so you have basically a cost, or array of costs; and now you can choose between your resource options, basically.

So, in our work we didn't do everything in the universe; we just tried to focus on the new utility size power plants, those are big size. And we didn't really address the DG level for the small PV or biomass technology. My understanding is that will be addressed in a different report.

The methodology we used was really simple; levelized cost basically. And in understanding what levelized cost is, is basically it's the constant level of revenue necessary for each year to recover all the expenses over the life of the power plant.

Meaning if you put equity, as a developer you put equity in, you want a return on your equity, and that would be part of the stream of the flow of the -- that's part of the cost basically. So that's what we call cost.

Levelized cost for any power plant is a

function of, of course, fixed costs, which varies annually basically. Depends on the capital, O&M and fuel costs.

The capital costs are basically two parts. Either you get to finance the power plant with debts, or you got to finance it with equity, or a combination between both. And most of the power plants are a combination between both.

On the debt financing basically you structure your terms basically, those are very rigid, and those are bank loans most of the time. And basically they are functional, loan amounts, the number of years of financing and the rate, the interest rate you are borrowing with.

Again, these are required, these payments are required on monthly basis to be made, or periodically. Could be quarterly or annual payments or what-have-you, but most of them are monthly basis.

Of course, before you get to that level with the bank you have to do what project financing require you to do, which is a lot of other big set of analysis to get to the bank. And the bank will agree with you. Like permits, for example, and contracts and some other things.

On equity financing, this is different because you are putting out the money out of your pocket, so to speak. So you are -- and you're require certain return on that equity, which normally is a little higher than what you borrow money with from the bank.

That's repaid from the residual revenue. That mean you pay all your bills and you pay your mortgage, so to speak, on that power plant. And now you are collect the extras, that's your return on your investment. And sometimes you run the risk of not having anything left.

On the O&M costs, and those are basically they run for basically labor, managers and insurance and basically your typical O&M costs. Those costs, they do not vary to the operation mode of the power plant. If it's an intermittent to peaking power plant basically. They are fixed for the -- the type is not very sensitive to the function of that particular power plant because you still have to pay labor, you have to pay managers, and you have to pay insurance.

The variable costs that definitely varies with your output. And most of the time for combined cycle or for a simple cycle or a peaker unit, that would be the biggest chunk or the biggest component will be the fuel consumption or fuel cost.

Additional to that would be maintenance expenditures. And forced outages that would be part of your variable costs most of the time.

Fuel costs definitely will change over the time and is unpredictable, as we all know, and we heard about it for the last couple days now, compared to other costs of other components of the variable costs.

We use in our analysis the forecast for -- the fuel forecast, natural gas forecast, from our office upstairs. And that was December 2002. And it seems like people like that numbers for whatever reason.

Okay, our financial assumptions were almost fixed across all the technologies we looked at. We looked at 40/60 basically, or roughly 40/60 equity to debts. The return on the investment for the equity roughly 16 percent. The debt would be around 7.4 percent. And there is a lot of assumptions here about that 7.4 percent. Basically we are saying that the corporate has good standing on their credit, and that they are not having in a junk status with their bonds. And they have a AAA bond and they can be -- they can borrow at that lower rate.

Of course, if you look at the last line, that's the loan or the term of the financing; it's only 12 years, which most of the banks now are looking at that number. And basically most of the banks now, because of the uncertainty of the market, they want to collect the money sooner than later because later would be running the risk on not recovering everything.

Inflation rate we used 2 percent; and discount rate we used 10.8 percent. And the coverage, the debt cover ratio was basically 1.5 percent.

These are the results comes out after we used this method I explained, and also the assumptions, these are the results. And I want to point out something here. This table is available in your report; however, the new things here are the numbers are in bold. These are for wind, hydro and some of the solar and down in the geothermal.

The reason they are in bold because they are different than what you have in the report. The difference is that we neglected basically in the draft report to remove some of the interconnections and the permitting costs. We left them in there in most of our spreadsheets. And you see that spreadsheet number 11. Normally for every technology you have in the appendices you will have 13 tables. Table number 11 from each one of those is the one that has the interconnections and it has the permitting. So those they have values in most of the tables, or these tables they are in bold, or technologies in bold.

What we did here, I just went in; we zeroed them out. And basically the new numbers looks like this. The final report will reflect that.

So what do we watch for as we are looking at this report? Basically a lot of things. There's a lot of things we included in our assumptions in this report. And you saw those are very much summarized in the appendices.

But other things we did not consider, for many reasons. Number one, most of these power plants are site-specific. Meaning if you will build in the, you know, north California versus southern California. Or if you build your power plant a combined cycle or simple cycle in basically an AQMD area, Air Quality Management District area, it will vary a lot basically in the permitting costs, as an application you will pay to that District. It will vary for the way you are going to site that power plant and mitigate the impacts of the power plant from environmental aspects like air quality emissions and cost of offsets, basically, in the Bay Area will vary a lot if you put that same power plant in San Joaquin Valley.

And I'm not talking here about emissions only. I'm talking about all environmental aspects, meaning that perhaps water might be a problem in certain area, so you would be -- the city would be able to supply water to the power plant. Or you have to dig your own well to pump this water, for example.

Biological impacts could be very significant if you have a big size area you are putting your power plant on, and you use a big land use basically; so you have to mitigate for that. And also the biological impact could be a severe one.

Also, if you have a power plant, you are going to remove the existing facility, you're not going to pristine land, you are going to remove the existing facility and you are putting your own facility. We didn't consider, for example, the cost of removing that existing facility because, again, that's a site-specific.

Infrastructures. That goes for everything, transmission, gas, and waterlines, basically, that's the main three ones. How close are you to these things and how far are you. So these costs can have a huge impact on the bottomline. But, again, you cannot predict where you are going to put that power plant, and you have to take it by site specific.

So our analysis would show the bulk of the information, however it doesn't show these things, doesn't show these variables. Because, again, it's site specific. It depends on where you're going to put that power plant.

Once you choose to put it in area X, you get to see what are the factors that can affect that area. And you plug it in and now you know how much it will really cost you for that plant.

The other thing we did consider is a normal market condition, meaning that it's peace, not war. In war, as we see, we heard $6 and $11 for natural gas versus normal prices for natural gas. So there is spikes in the market during war. We didn't consider that when we are analyze our cost of generation over these power plants. We just looked at a normal condition which is peace.

The other thing is we used again the CEC long-term forecast. And I understand there is a lot of problems. A lot of people, they are criticizing that by saying well, today the price is that. And our answer to that is today is a short term or next month is a short term. We are looking at a power plant will be built for 20 or 30 years, so the long-term forecast is more important in this aspect.

Also what we did consider is the corporate credit status. We assumed that they are AAA bond status; the credit is reliable by Fitch, S&P and Moody. They told us that, yes, these corporations are in a good status; they are AAA bond.

The reason for that is it's very important because their borrowing power will increase as you having good credit. If you have bad credit, perhaps the debt ratio will change on you. And instead of 40/60, perhaps you go to 50/50 or the opposite, 60/40. Depends on the banks and how much they will trust you and how much credibility you have on your financial statements.

Also interest rate might go shoot up on you; instead of 7.4 and when you have bad credit, it might go up over the 10 percent, for example. That's a huge impact on the mortgage or the payment you have to pay every month or every period to your bank. So that's have huge impact on that.

The other thing we did not consider is the hedging for natural gas; the hedging costs for natural gas. And the price volatilities are not counted for. And the reason, there's two ways to hedge, either physical hedge or financial hedge. And we haven't considered either one of those in our analysis. So this is, it could have a big impact on the gas-fired technologies like combined cycle and simple cycle.

This is basically a word of caution. These numbers are not alone, by themselves, sufficient to choose between technologies. Meaning if you look at the table I presented with all the answers, say well, I want to put a portfolio, pick up the cheap one. That's not, by itself, going to help you to have a very good portfolio.

Because the choice should depend on the resource system portfolio, and the performance of the resource, itself. And meaning that do you need capacity more in your system versus do you need energy, more energy in your system than you have in capacity, for example.

So you have, as a portfolio manager, you have to see what you really need in your portfolio to put in, versus okay, this is the cheapest one, and I'm going along with the cheapest resource in general.

Another way of explaining what I'm trying to say here is if you have two resources, they are 30 cents a kilowatt hour, for example. One of them is can provide you capacity and energy; the other one can provide only energy. Which one will you choose? And the answer is it depends on what I need to put in my portfolio; is not that I need that one or that one, by itself.

If you look at reliability, you have to look at the resource. If you wanted to look at energy by itself, so that's what you need to be looking for.

These are the workshop questions. I hope I just went through them very quickly here through my presentation, basically. And I believe we have two people who wanted to have presentations before you. I believe Bill Marcus and Mark, and I'll ask Bill Marcus to come first because he asked us to do so, so he can leave. He has an appointment.

MR. MARCUS: I'm afraid I'm still back in the level of old technology here.

MS. JONES: It's more dependable, huh?

MR. MARCUS: Certainly less efficient. Particularly when I was out there printing these things up on transparencies at 2:15 this afternoon.

I think this will work. I'm Bill Marcus; I'm representing TURN this afternoon. And the reason I'm here is that not because we're thrilled with high electricity prices, by any means, but that if we're going to have them we need to plan for them and understand them and build the right portfolios to deal with them.

And we have a set of overall concerns. I think our first one is that these numbers, taken out of context, and I'm very happy to hear the staff's levels of caveats they're putting on these numbers, but these numbers, taken out of context, could be used as the benchmark for a renewable portfolio standard and we just don't think they're ready for prime time for that, for that purpose.

They could be used to make suboptimal policy decisions, and in particular we had concerns about the two technologies we looked at in the most detail, which were wind and combined cycle.

And I think I'm going to hit -- after talking to staff I understand a little bit more about what is going on here, that they've been trying to take some of these development, land acquisition and permitting costs out of their analysis. Might be better to put them into all sides of the analysis. But they made the decision to take them out, but they managed not to take them out of the wind project where they represent something like $5 a megwatt hour of the windmill's costs.

We also see that the cost of emissions offsets are missing. That's a site-specific element, but it doesn't make it any less real.

MS. BAKKER: Well, let me check, Madgy, the reason you wanted to take them out is because they're costs, site-specific, and therefore you would factor them in -- one would factor them in on a site-specific basis. And wouldn't that also be true for wind?

MR. MARCUS: I think there are a set of costs that would be factored in on the site-specific basis. Again, if we're moving towards something like a renewable portfolio benchmark we may have to take some kind of average of them, rather than saying they're zero. Because the windmill meeting the benchmark will obviously face whatever their site-specific costs are.

MS. BAKKER: But if you were going to do a level playing field you'd pretty much have to do the same then with the thermal power plant or --

MR. MARCUS: Yeah, I think that's true. And the other issue that came up, looking at these numbers, is that the staff numbers are dry cooling. And I know that it's been a very contentious issue --

MS. BAKKER: Are wet cooling.

MR. MARCUS: I mean wet cooling.

MS. BAKKER: Yeah.

MR. MARCUS: And there's a very -- it's been a very contentious issue in a number of siting cases for this Commission, so I thought I'd better flag it for you that the base numbers you have here have made a technological determination that, you know, clearly in siting cases you guys are going to be looking at it on a case-by-case basis, and that dry cooling has some additional capital cost, and has other issues of lower output and efficiency.

MS. BAKKER: But lower water costs.

MR. MARCUS: But then they have lower water costs, but it's not at all clear where the water costs are in the staff analysis.

Looking at O&M and other expenses, I think the overall concern that we have with the O&M is the $30 per kW per year looks low. Particularly when $13 of it is the amortization of an overhaul.

They basically say other than insurance, labor and that overhaul, it's going to cost them only $4 per kW to run the plant. We think that number is light.

SCR operations costs look like a generic plug to us, and a possibly fairly inexpensive one. Pretty low costs, they used identical numbers for combined cycle and a combustion turbine in total dollars, even though there's a fivefold difference in megawatts and probably a threefold difference in combustion turbine megawatts.

I put an Edison comparison down here. I recognize that it's a little bit apples and oranges, but I think the difference is not between a dollar and a penny; I think the difference is probably -- the truth lies somewhere in the middle with the SCR operating cost of a gas turbine.

It's likely that you'll need to replace the catalyst at sometime in the life of the plant. And in addition the staff model has no capital additions for any power plants. Capital additions, large items that have to be maintained. And there's no inventory of either fuel or spare parts in any of this analysis.

Heat rate numbers that are given, we have a concern with. Basically we agree with the staff that 6800 or a number like that is probably what one of these plants can do under the absolute best conditions, running flat out, just after it's been done with an overhaul and at moderate temperature.

But there's some real world elements that we're concerned about which would cause the actual performance of the plant, even if it's in a baseload mode, and not as a cycling plant, would likely be worse; including startups and ramp-up costs, partial forced outages, degradation on hot days, things of this sort that we've listed here. And we would think that probably a number closer to between 7300 and 7500 Btus per kilowatt hour would be a better representation of actual performance under baseload conditions, but real world baseload conditions.

MS. BAKKER: Let me get a clarification again from Magdy here now. It strikes me that were you to model a combined cycle you would reflect at least some of these operating characteristics in the simulation in which one of these generators was added.

MR. BADR: Right.

MS. BAKKER: Is that right? So, we might be able to actually verify that in real life a plant would have a higher heat rate on average?

MR. BADR: On average, that's correct. But the way we tried to do this is as we said here, as Bill mentioned, that the 6800 is --

MS. BAKKER: Full load.

MR. BADR: That's full load, running all the time. And even when you ramp it from 70 to 90 percent capacity or something, that is still fine. But he's --

MS. BAKKER: Right, but all I'm saying is that --

MR. BADR: -- talking about circumstances where --

MS. BAKKER: -- you've used an input assumption. You've just said, okay, we're going to say full load heat rate. And what he's saying is in real life, which doesn't fit on the table very well, it's going to operate in various stages of load from zero to full load and in between some. And that the heat rate degradation from that would be shown in a system simulation. But you're using an input assumption to fill out your table that says full load heat rate.

MR. BADR: That's correct.

MR. MARCUS: And I think that the difference that we have is that if we were using an input assumption to fill out a table like Magdy's for purposes of calculating, for example, a renewable portfolio standard benchmark --

MS. BAKKER: Right, right.

MR. MARCUS: -- you would probably be using a different number that would be -- it might be reflecting baseload use rather than lots and lots of cycling, but it would reflect the kinds of factors that are on this page.

MS. BAKKER: Sure, sure. It does get forced out and therefore it does have to ramp back up, and --

MR. MARCUS: Yeah, so I think that's the difference there.

I am going to show you the slide that shows $11 gas prices today provide a lesson. And by the way, the lesson is you're better off here than in New York City where it's 25.

MS. BAKKER: Yeah.

(Laughter.)

MR. MARCUS: But seriously, I'm not telling you that necessarily the forecast is bad. You've heard some criticism of your gas price forecast from Rich Ferguson. I'm not going to repeat any of what he said.

But what I do want to point out is that a forecast and certainty are different things; and it costs somewhere in the vicinity of half a penny a kilowatt hour to get certainty out of one of these analyses.

We've put down on this slide several examples of data sources for trying to calculate what this number is. I will tell my friends at Edison that I did not use confidential data to come up with it. I backed into it using public information.

(Laughter.)

UNIDENTIFIED SPEAKER: Where did that 80 cents come from --

MR. MARCUS: They had an application filed before the PUC to hedge, to spend $208 million to hedge gas prices for about a two-year period, and it was to hedge their QF generation.

UNIDENTIFIED SPEAKER: (inaudible).

MR. MARCUS: And they do change from time to time; I'm not -- I've got a couple of slides on wind. This one is simply saying, well, gee, we've had quite a few windmills coming in at a lot less than 5.4 cents for the California Power Authority and San Diego Gas and Electric's recent solicitation.

And my last piece of paper is mainly about some of the permitting development and financing costs. I do think there are problems with including these pre-development costs in wind and not in other technologies.

I think that the pre-development costs may be inconsistent with the assumption that you're looking at fully credit worthy entities that stand on their own and finance on their own, because there's an awful lot of equity and debt costs that look a lot like partnership structures, and things of that sort in the numbers.

And I also noted that the interest during construction was double counted in the staff's model there.

And this is a big issue because this set of costs on this slide that I'm complaining a little bit about are about $5 a megawatt hour when run back through the staff's model in approximate terms.

And I think with that I will stop and take any questions that anybody has.

MS. BAKKER: I have one question about your next-to-the-last bullet under -- no, the next-to-the-last slide. I'm pretty sure I know the answer to the second bullet, but the first one I'm not so sure.

Would wind bid low because they were getting an Energy Commission -- had won an Energy Commission auction and therefore were getting 1.5 cents or something like that?

MR. MARCUS: I think some of the smallest projects, I mean some of the lowest cost projects would be in that mode. There's a range of project costs between somewhere below 4 up to somewhere above 5. And I would say at the bottom end of that range you're probably right.

MS. BAKKER: Okay.

MR. MARCUS: You know, looking at the -- but the median number was somewhat below 5, and I was thinking more from the median than, you know, just looking at the range.

MS. BAKKER: Okay. Now, but for the San Diego ones, isn't it true that if they bid below the price they're not eligible for --

MR. MARCUS: That's in fact -- the benchmark there was 5.37 cents. And anything under that number would not be eligible.

MS. BAKKER: That's what I thought.

Okay. Thank you.

MR. BADR: For the benefit of the Committee and everybody else in the audience, Bill talks about the difference between dry cooling and wet cooling, and we consider wet cooling versus dry cooling.

The difference in capital cost is really significant, $25- to $30 million. Yes, there is a lot of people came before this Commission and they requested, or they ask at this Commission to site power plants with a dry cooling. But they weren't very successful most of the time.

I know of one or two, maybe three power plants they have dry cooling on them, like Sutter Power Plant, for example. And that was for very significant and very specific problems they have around the power plant.

So, not every power plant will be built a combined cycle or simple cycle, the developer will put on it or will install dry cooling just because it's better. The economics sometimes play a big huge factor in the capital costs, and if they can stay away from it they will.

If you look at how many power plants they've been sited with this Commission and how many of them have dry cooling, you will see that we're betting off considering the wet cooling technology versus the dry cooling, when we try to estimate this technology cost.

MS. BAKKER: Well, let me ask you a question there, because first of all, it seems to me that if you're predicting far into the future you could be looking at circumstances where water becomes progressively more of a challenge to California. And so, over time, it could certainly be the case that more and more of the new permitted facilities would face the challenge of better uses of water than cooling power plants.

So it strikes me that when you're predicting the future you do have to worry about whether that is a progressively more likely.

I don't know the answer to that. I'm just saying that when you're predicting the future, that's certainly a factor you need to keep in consideration.

The other thing is that some of these things where there are uncertainties, we deal with it by trying to put a fudge factor in there to deal with the fact that there's some probability of an additional charge. And maybe there's some way we could capture things like that. It's just an idea.

MR. BADR: You're absolutely correct. But, again, I have to go to the site specific.

MS. BAKKER: Right, exactly.

MR. BADR: Sutter, for example I know that very well, because I sited that power plant. They have a problem with the discharge water, and that will perhaps destroy some of the levees and they have causing problems to the farmers around it.

So the Commission Staff asked them to put a dry cooling on that particular power plant because of the discharge problem. And also the dry cooling is not going to solve the problem. You circulate water in the dry cooling a whole lot more than wet cooling, and therefore you concentrate toxics inside this water.

So you either have to clean it up before you discharge it, or you have to just discharge it somewhere where you don't care about the toxics in this water.

So, it's not, you know, dry cooling doesn't fit every -- again, it's site specific, I guess, that's my best description to that. It's not you can say this is better than that one. Or we prefer this one over that one because of the aqueduct or the water usage in California.

Again, could be an area where they use marine water all together. So we don't know where the power plant is going to be, but just by making the assumption on a specific cases, and use that as a general case, I don't think you'll agree -- I think you will agree with me that's not really kosher to do so.

MR. McCANN: This is Richard McCann with M-Cubed, and I worked on developing this model. I also just recently was working with the staff on the SMUD Cosumnes project on the FSA on reclaimed water use.

I mean most cases these power plants it is much cheaper even to use reclaimed water at a much higher cost than potable water than putting in dry cooling. And dry cooling is an option that's really, from an economic standpoint, and from a water conservation standpoint, really only viable in a case where you have, it is extremely expensive to bring water into a particular location, or they have a water discharge problem.

I mean if you don't have those two

problems, using reclaimed water is still cheaper than going to dry cooling. And in that case, you are not impinging on the state's water supply.

MR. ALVARADO: I think a lot of the points that you made, Bill, are valid. And I do think we want to sort of examine it, maybe look at other additional hedging costs. We may need to consider like to address the heat rate value questions and things like that.

So, I guess with Magdy's concurrence, I think we will try to examine some of these features a little bit further. Probably adding some hedging factors into the numbers.

MR. BADR: Most definitely. The hedging factor is one of the important factors that I pointed out in my caveats and definitely we need to look at that. And what was it --

CHAIRMAN KEESE: You don't look at tax credits, either? You haven't wrapped tax credits into the --

MR. McCANN: Tax credits are for each of the technologies that are available are included in the analysis.

CHAIRMAN KEESE: So wind would be --

MR. McCANN: Whatever federal tax

credits are available to wind are included in the cost estimates.

CHAIRMAN KEESE: Okay, so 5.42 is a net?

MR. McCANN: Right, net of those credits.

CHAIRMAN KEESE: Net of wind. It might be 6, I forget what the --

MR. McCANN: Yeah, it turns out that wind doesn't get many tax credits because the federal tax credits are over-subscribed and they allocate them.

MS. BAKKER: I'm still confused about the site-specific costs. I heard what you said was that you were taking them out because they were too site specific. And yet --

CHAIRMAN KEESE: Too variable.

MS. BAKKER: Yeah, too variable, and yet you put a power plant in a resource plan, it has development costs. What are you going to use?

MR. BADR: Oh, no, we did use the development costs. This is -- you have the capital costs in there; you have the O&M in there; you have the variable costs there. You have all the costs you need to establish that -- to build that power plant.

But what you don't have in there is the cost of the application for permit; you going to have the cost of the emissions associated with that power plant to get out, because mitigation --

MS. BAKKER: I followed what he was laying out there, and that's what I'm asking you. How are we going to deal with that? Pretend that those costs aren't there?

MR. McCANN: Well, let me answer one real quick question about this is that in this project, in the way that the costs were developed was actually for the renewable technologies it was a survey of different project developers, or people who were very familiar with their specific technologies of how the costs were put together for their projects.

They did not supply information all in the same format because they all thought about this differently. And so that what you would do, would get back is, for example, what happened with wind is they gave back a very detailed description of what their various costs were.

Geothermal was the same way. What we found in the solar was that there was less detail that was provided. Fuel cells even less detail.

So that when you look through it you will see that the list of items that are included are different for each one of the technologies for that reason.

Combined cycle, actually what we did is we used a number that the staff has been using for a number of years to estimate the cost of combined cycle. And I actually don't know this for sure, but my understanding was was that that actually included some development costs. But it was essentially a single number. It did not have the items broken out like it does for wind, where it has the land acquisition cost and all of those other components that are included.

So, there's less detail in that aspect. One of the things that we need to revisit is going back and breaking, finding out what we need to break out and exclude.

MS. BAKKER: Yeah, the first thing we need to know is if we have the problem, I guess.

MR. McCANN: Right. And the thing is looking at the costs that are in the AFCs where they do report them, are in very close to the range of costs that we have here in this model. So that it's not as though the -- unless the AFCs are excluding some of those other costs that we're not aware of, we are including most of the costs the developers are reporting in the AFCs.

MS. BAKKER: Okay.

MR. MINICK: Mark Minick, Southern California Edison. I apologize that I don't have a presentation to make, but I'm working seven-hour days trying to put together a resource plan for April 1st.

So I have just a few comments and this is one of the rare times -- and Bill and I have been adversaries for many many years -- that I'm going to agree with many of the things that Bill said.

First off, regarding your capital costs, I truly don't believe that you have included things like interconnection costs, transmission lines, gas pipelines, other outside costs, makeup water, precommercial owned and permitting emission offsets and things like that.

So we have a significant difference in what we think the costs are and what you think the costs are.

We also think your capacity factor for a CCGT is extremely high. And under the current conditions in California a unit would not operate at 91.6 percent. We think something more like 75 percent is much more realistic.

You also show no starts of the unit through the entire year. That's totally unrealistic. The unit is going to have starts, especially when it can't sell all hours or it has forced outages and things like that. So we think 50 starts for that unit would be more realistic.

In regard to the O&M costs I disagree with Bill. I think that $30 is actually too high. So we can send you what these assumptions are in an email after I get down from here.

Regarding your forced outage rates for that particular unit we think they're quite a bit too high at 4.6 percent. We think 1 percent forced outage rate for combined cycle technology would be substantiated by data that you can get out of various literatures and sources, and we'd be glad to back that up.

MR. McCANN: Yeah, that number came from the AFCs.

MR. MINICK: Okay, well, that's just simply too high based on FERC form 1 data and things like that.

As far as one issue that we have

difficulty with is duct firing. I think you'll find in your AFCs that almost every facility that's going in has duct firing. Duct firing is supplemental firing of gas in the steam section of the unit to give you more megawatts. Anywhere from 40 megawatts to 80 megawatts is typically what the duct firing will give you. It's very low cost, incremental capacity and at times of high temperatures and other reasons you can use duct firing to get your full output. So to get the output of your unit up produces less than what we anticipate. I think you should look at duct firing.

As far as your heat rate, I'm sort of between the two. 6800 is a heat rate that the manufacturers say is good for ISO conditions; and Bill says 73 to 75 is what it should be. We're around 7150. The reason we're at 7150 is because we looked at the unit in more of a typical application in California.

I'll back that up with you can look at the contracts for Magnolia and other resources that PG&E is making to people. They're guaranteeing 7300. So, I'm assuming they can do better than that, because they're putting that in their contract. But I don't think it's as good as 6800. I think that's ISO conditions.

As far as your startup fuel, you seem to have the same startup fuel for both CCGTs and gas turbines. One is more a four-hour state and one is possibly a 30-minute or less start, 10-minute start. It shouldn't be 10,000 MmBtus. It should be closer to about 2000 MmBtus for a CCGT and maybe 200 Btus for a combustion turbine.

Also the number of starts you have for your GT or your gas turbine is zero. Again, we think they are peakers, they'll be used for short periods of time on many days. And that's an error on your part.

Also your forced outage rate is .5 percent. Unless they've gotten a whole lot better, I haven't seen many GTs that have .5 percent forced outage rate. We think 5 percent is probably more realistic. It might be a little high, but we think .5 percent is too low.

Your heat rate for your GT is optimistic at 9300. Typically the big difference we have there is you've assumed an LM6000 for your peaker. We're assuming that you might build a Frame 7 for a peaker. So we'll have to resolve that difference. You might look at two kinds of peaking facilities. It's cheaper to build a Frame 7. So like the Sunrise project before put on the waste heat boiler for shorter duration operations than an LM6000.

Therefore, and it's cheaper on an overall capital basis. But that's a little higher heat rate. Those things are the kind of things you're going to have to work out.

Let's see, what else do they have real quick here. Some of your costs, I think, are a little high or a little low for your expenses for personnel at the site. The $80,000 was good a few years ago, but these kind of plant managers now are in high demand; we think $120,000 is a better cost.

MR. McCANN: Are they really still in high demand?

MR. MINICK: They're still in high demand.

(Laughter.)

MR. McCANN: Given Calpine's turbine cancellation?

MR. MINICK: Well, they haven't built all those plants yet, okay. So we think some of those costs are just a little bit low. And it isn't a big deal. And we'd be glad to send you what we think the costs should be.

Your natural gas price, I won't go into it. It's probably reasonable.

And some of the other salaries might be a little bit on the low side.

We also wanted to note that you put down the number of personnel for what looks like a single block, sort of let's say a 500 megawatt CCGT block. That's probably pretty close to right. As you build additional blocks of a station you wouldn't necessarily take that 23 people and --

MR. McCANN: Right, and this is only a 500 megawatt block.

MR. MINICK: -- cookie-cutter. Right.

MR. McCANN: I mean this is the problem with the site specific, you know, --

MR. MINICK: Right. But I think if people wanted to look at it, if you build a 1000 megawatt block or a 2000 megawatt block, because many sites you could do that over time, that the costs might go down because of additional savings in personnel and things like that.

MR. McCANN: Right.
MR. MINICK: Let's see, another issue not on CCGTs, I think you should use a 50-year life or a 60-year life for hydro facilities.
MR. McCANN: Yeah, that's a question of how long do you -- the economic life versus the physical life of the facility, and the amount of time that you'd expect to recover the costs.
Because, for example, the utilities carried those as 40-year lives in their books.
MR. MINICK: We used to use 50 or 60, and I think federal relicensing is every 50 years. So I think you build it for a 50-year life, and then you sort of realize it's --
MR. McCANN: Right, well, I know that PG&E carried them in a 40-year life.
MR. MINICK: Okay, I think Edison does 50, but -- so maybe 40 or 50, either one would be better than the 30 --
MR. McCANN: Right, well, this is -- the other problem is who's building the hydro plant.
MR. MINICK: True.
MR. McCANN: So, to a large extent the hydro plant, since there are no hydro sites really available, --

MR. MINICK: Right.

MR. McCANN: -- it's almost like a plug that's there. There's, you know, probably maybe another 300 megawatts of hydro that's available in this state.

MR. MINICK: Just, I'm looking for your credibility.

(Laughter.)

MR. MINICK: Make it 50 years and make everybody happy. I don't think it will change the end result that much.

Again, on wind, my concern isn't the cost necessarily of the wind; I've been at Edison 28 years, many years in planning, some years in operations. I'll be flat-out honest, wind energy is probably economic. You can't run the system on all wind. The operability problems are extreme.

And you haven't put any costs in there about how you cover winds going the wrong direction when you want to ramp, okay. You have to back it up with some other resources. I don't know whether you want to penalize wind for that, or just recognize it in writing. But wind doesn't necessarily meet your operability concerns.

And no disrespect to the CPUC, wind

isn't always there at the time of the peak. When you put in 1000 megawatts of wind, he'll stay that 250's there at the time of the peak, whatever; I'll say that it's 100. It's something less than 1000, okay.

So you have to realize your can't, even if it was economic, and you could 10,000 megawatts of wind, you can't run your system on all wind. And that needs to be recognized.

And that's sort of a quick summary. And I'll answer questions if you have any.

MR. BADR: Actually I have one question about your peaker LM6000 versus the Frame 7. I appreciate what you're saying, but we found that a lot of developers, especially peakers, they would like to have the LM6000 because they can build on it, like they will have a block right now, the peaking capacity sometimes is not all called on.

Like if you have a Frame 7F, you might have 170 megawatt available on peaking. But normally you will get maybe 50. You want to have 50 megawatts right now. So they build incremental the LM6000 of 50 megawatt, each three of them next to each other, for the same amount, 150 or 170 megawatt. So they can fire up one at a time and become cost effective for them instead of firing a big engine and they will not be cost effective for them if they don't use it, the whole capacity, 170 or 180 megawatt.

So they choose to use the LM6000, I think that's the rationale for it.

MR. MINICK: Right. And my discussion about that is that California's a 50,000 megawatt system. When you lose a 500 megawatt or a 1000 megawatt, you don't have to replace it. You can easily absorb 170 megawatts. If it's a little tiny utility, I agree.

But now I'll argue it on your side. Right now the emission standards for LM6000s are in the state at 2 parts per million. And LM6000 can easily make that. There's some discussion that a Frame 7, by itself, can't make that emission standard.

So I can see both sides of the issue. You might want to put both in again, with some of the caveats that there might be an emission issue with the Frame 7 unit. I'm not saying the LM6000s are wrong --

MR. BADR: Right.

MR. MINICK: -- I'm saying -- we're

pretty big, I mean Edison could probably absorb 170 megawatts at one particular --

MR. BADR: Right.

MR. McCANN: Right, but actually we're looking at this from a merchant developer standpoint. To them the loss of a big unit, given their contracts, is -- their financial situation, they're like a small utility.

MR. MINICK: Yeah, but have to sort of weigh both. It is quite a bit cheaper to build a Frame 7 than it is for a bunch of LM6000s on the economic standpoint, cost per kilowatt installed.

MR. McCANN: Right.

MR. MINICK: I haven't said which one's better yet, I'm just saying it's different applications. You kind of have to use one to the other.

MR. McCANN: And you'll notice the economic assumptions that are in here are for merchant developers, not for IOUs.

MR. MINICK: I thank you for your preliminary analysis. Again, I'm just getting back into resource planning. Edison has just formed a resource planning group. I did it for 12 years, and that was 12 years ago. I'm back again.

MR. BADR: Can we get your comments in writing?

MR. MINICK: Yes, I will send my comments to you in writing.

MR. BADR: Very good, thank you. Actually -- okay, go ahead. We have another presentation, that's why. But --

MR. HATTON: Do you want to go first, or --

MR. BADR: Oh, go ahead.

MR. HATTON: Okay. My name is Curt Hatton and I'm representing Pacific Gas and Electric today. PG&E first would like to applaud the CEC Staff on developing a comprehensive list of the cost structures of both renewable and thermal power generation resources. Clearly a lot of work went into the report that you guys have put out.

MR. BADR: However --

(Laughter.)

MR. HATTON: However, PG&E has a couple of observations and suggested changes regarding your preliminary report.

First I'd like to say that the most meaningful, overall cost comparisons occur when all significant cost components are included across all technologies.

Originally I was concerned with the fact that permitting interconnection costs had appeared to have been included for a majority of the technologies, but not necessarily all. In your presentation today you indicated that at least some site-specific costs were going to be excluded from all of the resources.

I think it's important that you try to develop some sort of proxy cost or average cost that you can put in there to try to capture what the cost differentials are between particular types of resources.

And I think it's important to include all costs including permitting, interconnection, infrastructure, their gas infrastructure or transmission infrastructure costs, or/and including environmental costs.

It may also make some sense to compare some of the individual cost components across technologies to see if they make sense. For example, land costs varied from I think $1000 an acre to $100,000 an acre. I think some of --

MR. McCANN: Yeah, that had to do with

rural versus urban settings.

MR. BADR: Right.

MR. HATTON: Right, but I saw at least four or five different costs for various land costs, and you know, you might have a rural cost and an urban cost, but I think you might have just two costs rather than three or four different costs.

You know, as SCE indicated, there's some of the CT starts, had indicated were zero. I thought this was a little bit unrealistic to the extent that CTs were going to be for peaking type activities. I think they would have some starts during the year.

Another issue is the long-term gas price escalation post-2013. It looks like you base it upon the escalation that occurred between 2012 and 2013. I would suggest rather than using a single year and then escalating at that year's escalation rate for the remainder of the study period to use some sort of trend. Maybe use the last five years or last three years, but try to take not necessarily the last year and then extend that out into the future.

I think that's most of the important

points. Thank you.

MR. BADR: Thank you.

CHAIRMAN KEESE: Thank you.

MR. BADR: I would like to get Duke Solar to do their presentation. Mark from Duke Solar.

MR. SKOWRONSKI: I'd like to take this opportunity to thank the Commission Staff for the time to present this. Essentially what I'd like to do is present a new technology that wasn't covered in the CEC report.

I'm an employee of Duke, but I'm here representing two companies, both Duke and Inland Energy. And I got a slide to introduce each company, and then get into a description of a new technology.

Duke Solar. Duke, the regulated utility, spun off Duke Engineering Services, and Duke Engineering Services spun off Duke Solar. So we have the name Duke, but we're no longer associated with either.

We have three business divisions in power gen, building, solar water heating and space heating. Most of our work is international. Water and space heating actually pretty big time in South America.

We recently signed a 50 megawatt SEGS type unit with the Nevada, Nevada power company, Sierra Pacific. And also we recently signed a 1 megawatt organic ring -- cycle contract with APS that we hope will be expanded to about 25 megawatts.

Inland Energy was formed in 1989. In 1992 they took on the development of the High Desert Power Plant. This is an 830 megawatt project that comes online I believe in April, a couple months ahead of schedule.

Inland developed it for about six or seven years, securing the permits, the rights-of-way, the land, permits and everything. And they sold most of the position to Constellation Energy Group, who is now basically the builder and owner of 830 megawatts.

Inland and Duke bring together very specific expertise, and we're marrying them into a solar combined cycle project. And before I get into the description of the combined cycle, we'd like to point out that we think that the CEC report might be a little bit out of date with respect to the costs presented.

There's an independent report, Sargent and Lundy. I don't have a website, but I brought a hard copy for you, Magdy, that you can have. And also another report, Pathway for Sustained Commercial Deployment of Solar-Thermal Technologies. You can access that on the web at the address shown.

Both these reports show solar thermal would be in the 8 to 10 cent range. And, by the way, the report, Pathway for Sustained Commercial Deployment, CEC was an active participant in that report. That report's about three years old.

And both of the reports, however, do not reflect, neither does the CEC report, reflect the cost of a hybridized plant.

Basically we think the hybridized solar plant combined with the combined cycle gives you the best of both worlds. We have load following, combined cycle generation with solar component. It offers an onpeak green generation with high reliability, due to the combined cycle backup, basically you can look at the plant as 24/7 because of the combined cycle component.

The levelized solar power cost is reduced. And this is because we have higher solar efficiencies when we integrate the solar ring -- cycle in with combined cycle there's certain synergies on the energy efficiency. We get economies of scale. A 200 megawatt steam turbine would have an average cost per kilowatt significantly lower than a 50 megawatt solar stand-alone steam cycle. And there's also commonality of infrastructure for transmission, substation, staff, maintenance buildings, things of this nature.

And in addition, since about 10 percent of the capacity would be solar, no matter what, emissions you have from combined cycle will always be 10 percent less than the competition, because 10 percent of this is going to be solar.

Basically for any engineers left in the audience, this is the cycle that we're proposing. You can go through it, but this was taken from the ASME 2001 forum. This was a study that tried to optimize, maximize the use of the solar fraction into a combined cycle.

We have two sites. One is Harper Lake, which is a two square miles parcel. It actually was to be the continuation of SEGS X, XI and XII. We have 10,000 acrefeet of water, and we're looking at making this into some sort of an energy renewable park with biogas burning cow manure and also solar.

We have transmission; might have to be upgraded. We have access to three gaslines which would augment the solar plant.

This is a view of an existing power plant. This is the High Desert Power Plant that's coming online in a couple months; 830 megawatts. And if I can draw your attention to the top part, right in this area here, we're looking at putting in High Desert Power Plant Number Two. This is the one that will be solar hybridized.

The site is already, quote, sullied, if you will, so we think we can piggyback on permitting, and the transmission, the water rights and everything that have already been negotiated. And, again, Inland Energy is the primary developer of this proposed power plant. And Duke is partnering to provide 50 megawatts of solar fraction.

This plant, by the way, will be scaled down. The High Desert Power Plant Number One is 830 megawatts. And we're looking at about 450, two Frame 7's, hybridized with 50 megawatt solar component which would give you approximately 500 megawatts total.

Southern California high desert, it's a premiere area for solar thermal. Inrale (phonetic) has categorized various sites in the United States, and this is one of the top rated sites. And it's high altitude, relatively high altitude, about 2500 feet. This reduces the haze and the scatter.

Solar thermal is a little bit different from PV, in that we need direct normal insulation, direct normal sunlight. And it's got a little bit of dust or aerosols or whatever that scatters the radiation and you can't focus it. So, we like to have it fairly high up, and the desert is a perfect area for that.

Low-cost land; it's got infrastructure, gas, water. Transmission may need upgrading. DWP has some space in their line; we're working with them on that.

High insulation obviously. Minimal number of cloudy days. And we have an existing site to piggyback permitting.

My take-aways here is that solar provides competitive green energy. In lieu of

Duke as a manufacturer and proposed developer quoting a price, what we like to do is simply recommend that you use the impartial objective reports that we referenced, or any other one that you can come up with.

But, we think that the number that you generated independently are high. Hybridized solar plant combined with combined cycle plant does offer flexibility and allows utilities to use the least cost best fit criteria to maximize use of this technology.

It definitely provides a lower than stand-alone pricing, and we're looking at probably anywhere from 10 to 20 percent cost reductions from the stand-alone price.

There's other hybridizations possible with biogas and geothermal.

Conclusion and recommendation. Again, we feel the solar energy costs in the draft report needs to be revised to reflect STAT or state of the art, up to the date solar design and cost. In addition, we'd like to have another line, if you will, in the report or description that shows a solar thermal that uses a hybridization concept with a combined cycle.

And again, maybe a mention that we haven't done significant work in this area, but you definitely can hybridize with geothermal and biomass. In particular, geothermal is attractive, because basically if you use what you call a flash system, what they generate is saturated steam. And we can take that saturated steam and add pure super heat to it. So every solar Btu that you put into the cycle basically comes back to you at the efficiency of the turbine of the generator.

So right now when you go through a traditional -- cycle, we're about 37 percent efficient. But if you add it to a geothermal cycle, you're about 90 percent efficient, because you're just adding super heat. And the only loss that you incur is with the turbine and the generator. The turbine's about 90 percent efficient; generator's about 98 percent efficient. So you don't have to go through that latent heat vaporization concept, because it's already being performed for you with the geothermal cycle.

That's it. Any questions?

CHAIRMAN KEESE: What is your timing on these projects?

MR. SKOWRONSKI: 2007, 2008, depending

on the permitting process. If we go with the George Air Force Base, that probably will be quicker. Harper it's more of a start-again of the permitting process.

CHAIRMAN KEESE: Thank you.

MR. BADR: I really appreciate your input on this, but before you leave, your numbers are site specific. Basically you looked at High Desert and you analyzed the High Desert and how you can tag along on High Desert, and you put your solar system. And you used the waste steam basically from the steam turbine or the waste heat. And you used it for your molten source, or for your reservoir to continue with the --

MR. SKOWRONSKI: We're not looking at storage, per se.

MR. BADR: Okay.

MR. SKOWRONSKI: Storage, we're not looking at storage, per se, with a combined cycle. We would just ride on the combined cycle. In other words, we provide duct firing. And if we ran into clouds or maintenance, you still get the capacity through the duct firing.

MR. BADR: Okay. The second question is can you provide some numbers to this technology?

You mentioned something about 7 cents and 10 cents, that's what I heard, 8, 10 cents, or something like that. Can you provide some, you know, assumptions. Assumptions like I spelled out in my appendices. For this particular technology and how you derive that number?

MR. SKOWRONSKI: No. I'm not being facetious. Actually, we had a long conversation with my boss, and we just think that the playing field is highly competitive, and we reserve, you know, the right to be relatively secret.

Besides, manufacturers' estimates sometimes are, you know, self serving. What we'd like to do, again, is just reflect back to the objective reports that have been done, that we've had input into these reports.

But to get into the specificity of pricing, we think we'd undermine ourselves.

MR. BADR: There is a lot of assumptions. As you see, there's 13 different tables in every appendix for every technology. To chase a new technology such as yours, and you tell me that you are not willing to provide any information about it because it's so secretive, where do you think I should be going out and grab these numbers, or find these numbers?

And how close are these numbers to what we have? It seems like you took the combined cycle out of the equation of generating what you are doing because you are tagging on the combined cycle. This is very similar to appendix N, when we used the thermal plus gas, but minus the gas because you already have an existing gas power plant.

Our number shows 15 cents. You are talking about 10 cents. If you take the capital costs associated with the gas part of that component, perhaps it would come pretty close to where you are talking about, -- this is true.

MR. SKOWRONSKI: In general we think the reports are pretty close to our estimates. The two reports that both the CEC participated in, or one of them anyway, we participated input on both these reports.

And we'll work with you as much as I can with respect to, you know, the cycle that we're trying to define. But it's not just added gas costs, because when you combine cycle the concept you're adding heat at the right places and there is a synergistic relationship on the efficiency of the solar Btus.

MR. BADR: I wasn't mentioning just the gas; the components also -- the gas, as well, like the --

MR. SKOWRONSKI: Okay. We'll get something to you, but again, excuse my cryptic behavior, but you know, we're knocking on doors and we're talking prices, and you know, that's the name of the game we have to play.

MR. BADR: Right. Thank you.

MR. ALVARADO: I think I can say that this is the end of this workshop.

CHAIRMAN KEESE: That's it?

MR. ALVARADO: I don't know if there's anyone else of the last few folks over here?

MR. SKOWRONSKI: I got a question.

MR. ALVARADO: Sure, Mark, please.

MR. SKOWRONSKI: On your schedules, the listings of technologies and pricing, I notice you have fuel cells and fuel cell hybrid in particular that it seemed extremely optimistic, especially on the hybrid. You showed 2004 a cost around 10 cents. And I happen to own the patent -- I don't own the patent, Edison owns the patent, but I'm the inventor of the small turbine fuel cell hybrid. And I stayed pretty close with that technology.

And I called GE and Westinghouse and they're talking about 2007, 2008 before that technology will be available. And even then they're talking about niche markets. So commercial viability probably is at least six, seven years away.

MR. BADR: So you think the numbers are high or low or --

MR. SKOWRONSKI: Well, I mean nothing's going to come online in 2004. You'll probably wait another five years before you have the market entry in that technology.

And probably at that time I would think the numbers do look about right. But, it's not going to be next year.

MR. BADR: So what you are telling me is that we should scrub it, take it out of the report or --

MR. SKOWRONSKI: Yeah, I don't think it's viable. It's not there yet. GE just staffed up in Torrance to produce the product. And Siemens-Westinghouse has hit a snag because it didn't really work. They tested it down at UCI and they had some turbine problems. And they're putting it back another year, year and a half.

MR. BADR: But I also heard you saying that if it comes online in year 2008, 2007, or 2009, you think the numbers would be correct?

MR. SKOWRONSKI: My gut feel it's about right, yes.

MR. BADR: So I think you have no objection, there is no harm to having it in the report then?

MR. SKOWRONSKI: Well, 2004, I mean you're saying that might be a viable option for somebody in the near term, and I don't agree with that.

MR. BADR: Thank you.

MR. HALL: Hi, Stephen Hall. I'll try to keep this very very quick because I know everyone wants to go home.

I just had a question/comment about the capital costs for the natural gas combined cycle plant. And specifically around the issue, the old bugaboo about externalities.

There is a capital cost in there of $25 million for pollution control equipment. But beyond that, of course, there is greenhouse gas emissions, emissions of NOx, precursors of ozone, et cetera.

And I guess my question to the Commission is, is there a policy rationale for excluding environmental externality analysis in looking at natural gsa combined cycle?

CHAIRMAN KEESE: Well, I would defer to staff, but I don't think we looked at environmental externalities. I think --

MR. BADR: Well, -- go ahead, sir.

CHAIRMAN KEESE: Go ahead.

MR. BADR: Well, you talked about two things. NOx, for example, and all the criteria pollutant are required by law to be mitigated.

MR. HALL: Right.

MR. BADR: So, one might argue that since they are fully mitigated and that cost is being paid for, this is not external costs anymore because it's already built in. Okay? So the cost of the criteria pollutant, let me spell them for you, NOx, SOx, PM10, CO -- CO sometimes is not mitigated -- and PM10. Those would be required by most of Air Quality Management Districts to be mitigated.

So, however there is a CO2 emissions,

that's not required to be mitigated. And there is other environmental costs, not necessarily emissions, but could be like as I mentioned earlier in my caveats, biology, land use, visual, you name it, water quality. There's other aspects of that. It's not included, and the reason it's not included here, not because of any policy the Commission has, because it's a site specific --

CHAIRMAN KEESE: Site specific, that's what I would think.

MR. HALL: Um-hum.

MR. BADR: Right. It's not -- if I do externality, I would have tons of argument about the numbers, and I deviated away from the cost or the comparison costs of what we tried to do. The focus of the work is to be able to compare between this technology and the same level plane.

So if I have to add externalities, perhaps I would just direct everybody to look at that, not necessarily what we're trying to do. This is one thing.

The other thing is using this report, the way you should be using this report is to be able to compare the analysis or compare the technologies to each other; not use that particular absolute value for that particular technology, as a cost to develop it. To be able to compare, just a rate to say, okay, which one is which, and what kind of technology do I need to have in my portfolio and which one I don't want to have in my portfolio.

So, not necessarily because we didn't add a lot of things like externalities is one of the thing. So, you know, you have to acknowledge that. You don't just use that number by itself to just comparison, as a comparison to put like ranking between all these technologies.

MR. HALL: It's site specific is what you're saying?

MR. BADR: It is site specific. All the mitigations are site specific. We can give you an example, a quick one because we are really late.

MR. HALL: Yeah.

MR. BADR: If you will buy -- if you are siting a power plant in the Bay Area Air Quality Management District, and you wanted to buy PM10, good luck. All right? Because they don't have any, or they are running very dry.

Okay, now if you go to San Joaquin Valley you perhaps have a better luck. The cost of the PM10, a ton of PM10 in the Air Quality Management District could be humongous. I don't want to give a value on it.

If you go down to San Joaquin Valley perhaps you get $3000, $4000, which is very reasonable.

So you have other things also. The permit application, itself, is $350,000 for AQMD in the Bay Area. You go somewhere else, maybe $20,000, maybe none. So it depends. These values vary a lot, you know, it's not like a small difference. It's a huge differences between them, and depends on what is required to be mitigated and what's not required to be mitigated.

I'll be very reluctant to consider this externalities or societal cost to add here. The reason, again, for that report is to establish costs for to develop that technology, and be able to compare between these technologies together.

MR. HALL: Um-hum.

MR. BADR: Okay? And I think I give a lot of credit to my colleague, Benjamin, for choosing the title correctly. It's a comparative cost of technology for the electricity generation technology. Okay?

So it's not meant to be an absolute value. You will say, okay, I want to sign a contract for that because CEC told me that. All right? That's why the reason for the caveats.

MR. HALL: Okay. But maybe for greenhouse gas emissions, which are not site specific, that environmental adder could be considered?

Anyway, thanks very much.

MR. BADR: I'm sure.

CHAIRMAN KEESE: Yes. I'm sure, you know, once we get around to policy, this is not policy yet. I mean it has policy implications. But once we establish the baselines in all this, then we move on to policy. And what is the policy. And I'm you know, sure renewables are -- the renewables are going to be a part of the picture. Not picking the lowest cost generating system in the state.

Well, I thank all the diehards for hanging in here.

MR. SKOWRONSKI: All four of us?

CHAIRMAN KEESE: Yes.

MR. BADR: Thank you, Commissioner, for sticking.

CHAIRMAN KEESE: Thank you. It's a two-day good start. Thank you, Karen. Sort of messed up your schedule, too.

Thank you, everybody.

(Whereupon, at 5:50 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, VALORIE PHILLIPS, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 2nd day of April, 2003.